COMMITTEE WORKSHOP

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

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In the Matter of:                  )
                                   ) Docket No.
Informational Proceeding and       ) 03-IEP-01
Preparation of the 2004 Integrated)
Energy Policy Report (IEPR) Update) Aging Power
__________________________________) Plant Study
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CALIFORNIA ENERGY COMMISSION

HEARING ROOM A

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

TUESDAY, MAY 18, 2004

10:04 A.M.

Reported by:
Peter Petty
Contract No. 150-01-005

COMMITTEE MEMBERS AND ADVISORS PRESENT

John L. Geesman, Presiding Member

James D. Boyd, Associate Member

Chris Tooker, Advisor

Mike Smith, Advisor

STAFF PRESENT

Matt Trask

Eileen Allen

Sandra Fromm

Dave Vidaver

Mark Hesters

Matt Layton

David Abelson

Dale Edwards

ALSO PRESENT

Gregory Blue
West Coast Power
Dynegy/NRG Energy

Tim E. Hemig
NRG Energy, Inc.
West Coast Power

Jack Pigott
Calpine

Steven C. McClary
MRW & Associates

Audra Hartmann
Duke Energy North America

ALSO PRESENT

Scott Peterson
San Diego Gas and Electric

Tom Miller
Pacific Gas and Electric Company

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P R O C E E D I N G S

10:04 a.m.

MR. TRASK: First I want to apologize for today, for our lack of coordination with the California Public Utilities Commission. They are having a rather important workshop this morning that a couple of the generators that wanted to attend this meeting had to choose between the two, and chose the CPUC.

We also understand that the ISO is having meetings this morning with FERC. And just heard that there's also a golf tournament by the California Power Association, so I'm sure that's draining away quite a few people, as well.

So, we have several options and I'd like to explore these with the Committee and with the audience. We can continue this meeting or we can renotice this meeting and have it in about two weeks. We can have a preliminary meeting now and follow it up in two weeks.

And then the other option, for instance, Reliant Energy very much wanted to be here today and they offered to do individual meetings with staff and with the Commissioners, if that was desirable.

So, with that --

PRESIDING MEMBER GEESMAN: Well, I guess let me try to describe the Committee's interest, both in this workshop and in the workshop process overall.

We want to make certain that the methodology that the staff utilizes, and also key assumptions that are used in the study that we're performing are vetted at each significant step along the way.

Our overall ambition is to try and bring some factual understanding to this subject matter. And to the extent that we can, take it into the empirical realm and out of the rhetorical realm.

So I have a real interest in making certain that the various different stakeholders do have a full opportunity to review the staff's materials, listen to staff's presentation, respond to it, and presenting any materials you think should be brought to the Committee's attention.

I guess my inclination would be to see if there are any here today that are prepared to do that. I'm not wild about the Reliant suggestion, although I certainly appreciate their motivation for doing so.

I'd prefer that we do this in a workshop setting where everybody has an opportunity to listen and where we do have a transcript developed. I think that would probably serve our purposes better than one-on-one meetings.

MR. TRASK: Sounds good. Maybe I'll open it up to comments from the floor about interest to go ahead today, and have staff do their presentations. And then I know, for instance, Greg Blue with Dynegy would like to do a presentation related to one of our panel discussions.

So, what's the thoughts from the audience of either postponing today or going ahead today, and then have another followup continuance meeting in about two weeks? Any thoughts?

Greg.

MR. BLUE: I propose that since all of us made the effort to get here that we go ahead and present what we have today and then if we do have a meeting, another meeting. A lot can happen in two weeks, and as you'll hear from me in a minute, time is of the essence.

MR. TRASK: Very good, very good. Okay. Well, with that, the first thing on the agenda is the opening remarks by Commissioner Geesman and Commissioner Boyd.

PRESIDING MEMBER GEESMAN: Well, I just made mine. Commissioner Boyd, do you have any?

COMMISSIONER BOYD: Very little, and in deference to those who did make the sacrifice in coming here, I'll yield on time. Other than to say that this is an ever-increasingly more critical subject matter that we're dealing with. The interaction of gas and electricity and the uncertainty with regard to the economy and population growth and what-have-you have made this a very pressing subject.

So, I'd say press on and let's hear what we have today. And continue with others in the future.

PRESIDING MEMBER GEESMAN: Okay, Sandra.

MS. FROMM: Good morning; I'm Sandra Fromm, the Assistant Project Manager for the 2004 Integrated Energy Policy Report Update. I'd like to welcome you here today and thank you for your participation in this workshop.

Today's workshop will be on aging power plants. It is one of three elements in the update which also includes components on transmission and renewables.

We expect to have a draft aging power plant study in July and workshops following that in August. I encourage you to subscribe to the IEPR's email list server which is found on the Energy Commission's website on the IEPR website. And it's at www.energy.ca.gov. You'll receive electronic notifications of workshops through that.

Any presentations made today by staff and also presenters from the audience will also be posted on the web. Paper copies of the staff's presentations, the agenda and a sign-in sheet are located at the table at the front entrance. Make sure you sign up on there; and also, if you check a box on that sign-in sheet, we can also sign you up on the list server.

We would appreciate receiving all your comments to today's workshop by Tuesday, May 25th.

With that I'd like to take care of a few of what we call housekeeping items. When you come up to the podium if you could state your name and affiliation, if you have one. You can also provide a business card to the court reporter.

When you're at the podium if you could

speak directly into the microphone that way the court reporter can get an accurate record of what is stated here today.

Restrooms and water fountains are located outside the hearing room door to the left. There's a snack shop that serves sandwiches and coffee upstairs on the second floor. And lastly, I'd ask for your courtesy to turn off your cell phones or turn them onto the silent mode so that they won't distract the speakers.

With that, I'd like to turn the workshop over to Matt.

MR. TRASK: Thanks, Sandra. Can everyone see the presentation okay?

I have several members of the staff with me today and we'll be introducing them as they come up and speak. I'm going to start off with a sort of a synopsis of where we are and where we're going.

We had a workshop, the first workshop was March 24th. At that workshop we explained that the three objectives of our aging power plant study were to examine the role of the aging plants in system reliability. That's both local and region, systemwide.

To look at the environmental and natural gas implications of both retirement of the aging units and continued operation or continued reliance on these units.

And to analyze a very wide range of possible retirements and the implications of those retirements.

As Sandra mentioned, this is part of the 2004 update to the Integrated Energy Policy Report. We started with a proposed list of 66 units. We used a criteria of built before 1980, natural gas fired, nonpeakers. And we laid out at that time what we knew about the plants, their capacity factors, their emission factors, total emissions, plant technology, things like that.

All those are available in our presentations that we gave on that day that are still posted on the website that Sandra mentioned a little bit earlier.

Since that last workshop we've been busy. We've had about I think 14 or 15 meetings, individual meetings with the California Independent System Operator, the merchant plant owners that own units that are on our study list, the investor-owned utilities and some of the municipal utilities that are also on the list.

We're gathering information and data from a wide range of sources. The ISO is a very crucial partner in this study, to obtain the data information we need to assess the potential risk of retirement and then analyze the effects of those retirements.

We're also getting very good cooperation from the plant owners, themselves, in providing information. And we're looking at getting information from these other sources and agencies that we listed up here.

One of the things we did after gathering this information and talking with people was we narrowed our list of units as far as what we're studying for reliability issues to 50 units. We're still doing a full environmental analysis and natural gas use analysis of the 66 original units. But we felt, for a variety of reasons, that we could limit it down to 50 units for our reliability study.

PRESIDING MEMBER GEESMAN: What are some of those reasons, Matt?

MR. TRASK: I'll be getting to them here.

PRESIDING MEMBER GEESMAN: Okay.

MR. TRASK: One of those -- in fact, I think I'll just -- okay. And Dave Vidaver will mention it, as well.

One of those -- here's a map that just shows the 24 plants, I believe it is, of the 66 units, 24 plants. You can see most of them are in the Los Angeles area or southern California area. A few in the Bay Area; and one up north in Humboldt. Here's another representation.

When we started looking at this we started looking first at the municipal units, which are here, except for Hunter's Point is not a municipal unit. And first we found published resource plans, for instance, by Los Angeles Department of Water and Power, what they intend to do with their units at Scattergood and Haynes. Very solid program there for repowering those units. We don't feel that there will be any retirements from those.

And we also talked to the municipal utilities that own the other units, Olive and El Centro. That would be City of Burbank and Imperial Irrigation District. And also have good confidence that those units will not be retired anytime soon. There's a variety of reasons for that, which I have up here. Most of them have already been retrofit or the retired units have already -- excuse me -- most have already been retrofitted to upgrade to air quality standards.

Municipal utilities, of course, have guaranteed cost recovery of their generation. They are seeing opportunities to participate in the spot market, as well. And we think, with all those factors, for instance that any retirements that have occurred are essentially always accompanying with repowerings.

So with that we thought we could reduce the list to 50 units for analysis of reliability.

PRESIDING MEMBER GEESMAN: Did the munis mention to you the potential for participation in the spot market? Or is that simply something that you're attributing to them?

MR. TRASK: A little bit of both.

PRESIDING MEMBER GEESMAN: Okay.

MR. TRASK: It wasn't a strong factor for any of the municipal utilities, they just noted that that was an opportunity.

PRESIDING MEMBER GEESMAN: Okay.

MR. TRASK: It does seem to be, and this

kind of feeds into the next part of my presentation, the summary of the comments we received, both in our meetings and in writing. It does seem to be a general theme that people think that there will be opportunities for increased generation at some of these plants. But that some of them may not be able to hang on.

The first comment there, all the generators that we talked to were unified in their expression of the need for changes to the market structures and the must-offer requirement. Some of the other factors they say, and these were confirmed by other sources, that aging plants do require significant amount of maintenance to be able to participate in the markets that they participate in, which requires quite a bit of money to spend on them.

The gist of the comments so far does seem to be that retirements are highly possible. But pretty much everybody's holding on, or it seems to be somewhat holding on for the other guy to retire. Of course, that would improve the situation for those that remain.

The aging plants, again these are comments from the generators, primarily, aging plants do provide valuable service, especially to the local reliability. Some services like blackstart and so forth are supplied by these aging units and are crucial.

The aging plants tend to operate in a deep cycle mode. The come on early in the morning at very low power levels. This is when they do operate at all. And then ramp up during the day to the peak levels, and then ramp back down in the evenings. This is not the way they were designed. They were designed as baseload plants. And this deep cycling does create mechanical stress that does cause increased maintenance needs for these units.

DR. TOOKER: Is there an assertion here, an assumption that if the market was changed, if the structure of market was changed that the operational profiles of those units would change?

MR. TRASK: There was certainly the desire. I don't think anybody would expect that to occur anytime soon. Just because, well, of course, the nuclear units are baseloaded. And then the newer combined cycle, of course, can, with much better heat rates, can supply baseload power considerably cheaper on a day-to-day cost basis.

Although it was interesting that at least one generator of these aging units said that they could compete and would like to compete directly with peakers for peaking capacity. And that they felt that they could do it at a considerably cheaper price than the peakers, simple cycle peakers.

DR. TOOKER: Even with the maintenance requirements and the fact that they're operating in a mode they're not designed to?

MR. TRASK: Well, you're correct. There was only one generator that said that, though; others did comment that with the way they think these units are operated that they're still not quite competitive with new combined cycle plants.

One generator said it was very close and will provide information to show that the combined heat rate or the aggregate heat rate of an aging boiler unit, considering the way they're operated on the intermediate peaking or on the shoulders, that they're just about a wash with a new combined cycle plant on aggregate heat rate. We're looking forward to getting that information and verifying it.

Another uniform theme from all the generators and pretty much everybody we've talked with is that market uncertainty may cause retirements, but it's also preventing new plant construction. So the same economics that the aging plant owners are looking at and considering to retire are also the same exact factors that developers are looking at whether to go forward with new plant construction.

One of the desires mentioned by the ISO was to have a noticing requirement for plant retirements or moth-balling. Occasionally I guess they've found out, after the fact, that plants have been retired. So they've expressed a desire for a minimum of 30 days and more than that, if possible, of a notice before retirement.

And the last point I've already mentioned, that the efficiency of aging plants are closer to new plants when they're cycled heavily through the day.

PRESIDING MEMBER GEESMAN: Isn't there a federal plant closure statutory requirement that involves, I think, significantly more than 30 days of notice?

MR. TRASK: I believe you're correct.

That's a relatively new law, and perhaps some of the generators can speak on it more authoritatively than I. But I do believe you're right, that there is a noticing requirement --

PRESIDING MEMBER GEESMAN: My hunch is that may be able to give the ISO early notification. But if anybody has more specific information on that, I'd like knowing about it.

I have another question as well, and that is is there a common understanding or definition of the phrase local reliability? I'd like to try and impose one over the course of these workshops. And I don't have any particular preference for how we define that term, but I'd like to make certain that everyone is talking about the same thing, and that it's something that we can calibrate and hopefully quantify, because it is one of the terms that, I think, gets thrown around rather loosely.

MR. TRASK: We'll get into that a little bit deeper later on, but, yeah, I think that would be a valuable thing to come up with a definition of that. Basically we're looking at two general issues of related local reliability.

One is generation within the load

pocket. Whatever supplies that are supplying power into a load pocket can become congested or cut off during power emergencies or, you know, fluctuating events on the grid --

PRESIDING MEMBER GEESMAN: And how are you defining load pocket?

MR. TRASK: Good question. Basically it would be -- well, we first defined it when we looked at these unusual events, like the San Diego fires last year or the cascading outage through the whole west in 1996. And even stage one power emergency on March 29th.

When you look at the way the system responds to those kind of fluctuations, they often are created physically separate islands where the grids are no longer connected. But they're also, in a sense, islanded powers due to congested transmission lines where you just can't get power from one region to the other because that line is congested.

So we are generally referring to local reliability problems when an individual unit or a plant, itself, could, with the lack of that plant, or if that plant wasn't there, there could be problems with rolling blackouts, or even just power quality.

And certainly in southern California, for instance, there are five, at least five and maybe six lines, that come in and out of the Los Angeles area. We found that these aging plants are used quite a bit to alleviate the congestion on those lines.

And it's a very interesting phenomenon in that with the combination of the congestions on those lines that any one day you might be using any one of five or six different units. So it's been a challenge to try to assign the importance of any aging unit to that process of relieving congestion. But we're learning quite a bit about that from the ISO.

PRESIDING MEMBER GEESMAN: So, if I understand what you said correctly, a load pocket is smaller than the ISO's zones?

MR. TRASK: I think that's a general -- load pockets are not well defined. It generally is situated around those islanding events. But, yeah, you're generally right.

PRESIDING MEMBER GEESMAN: But are there a consistent number or location of islands? I'm trying to look at this from a state government policymaker standpoint. And the loose and flexible terminology is a hindrance. So, even though it may be simplistic, I'd really like to try and nail this down, the terms used, to as much specificity as possible.

MR. TRASK: Sure, --

PRESIDING MEMBER GEESMAN: And I'm simply using you as a foil. I intend to expect this of other presenters, both from the staff and from any of the utilities or generators.

MR. TRASK: Well, I think one of the valuable services we can provide is to come up with consistent definitions for the terms that we use both in the study and any other process looking at the reliability issues of individual units.

For instance, a little later we have Mark Hesters here to talk about one of the big studies that the ISO is undertaking. And in there you'll see the -- essentially the load pockets or the regional areas that the ISO is studying for local reliability problems due to retirement of aging units.

With that I'm going to turn it over to Dave Vidaver of the electricity analysis office to talk about the role of the plants in the system.

MR. VIDAVER: Good morning, Commissioners, and the rest of you. I don't tend to keep very still when I speak, so I may up-end the microphone at a point.

I want to go back over a couple things that Matt said. Initially we came up with a list of 66 plants to look at. They're up on the screen. You can see that many of them are located in the Los Angeles area. There is a list of the plants that we've looked at. We're not looking at all of the units. We're looking at 66 units at 24 plants initially.

One thing we've done, as Matt mentioned, we eliminated the municipal plants from a discussion of reliability and the retirements of aging plants for reasons that Matt went into, and I'll go back over it quickly.

A very large share of these plants are in Los Angeles. More of those in the Los Angeles basin are at risk of retirement than even this graph indicates, this map indicates. Humboldt, the plants in the San Diego basin, three of the four plants in the San Francisco Bay Area have RMR contracts, and thus are at less risk of retirement in the short run. We'll go into that.

The plant farthest to the southeast is one of the units owned by IID and El Centro. It's a muni unit. We don't think that's at risk for retirement.

So we basically have plants in the L.A. basin, Coolwater, Moss Landing, Morro Bay and Contra Costa 6 in the Bay Area as the remaining plants. So, a disproportionate share of the plants at risk for retirement are located in Los Angeles.

These are the muni plants that we eliminated for reasons I'll shortly get into. We think they're all going to stay online with the exception of Hunter's Point, which everybody would like to see retired as soon as possible. There's some consensus regarding that.

These muni plants constitute about 2300 megawatts of capacity. The initial list of 66 units was about 17,100 megawatts. So, we're now down to about 13,800 megawatts of units that we're looking at.

Matt went over the reasons that we don't believe the muni units are apt to retire. I want to clarify one thing. Munis, as a rule, are short. And in 2000/2001, to the extent that they were dependent upon the spot market, they suffered greatly.

Based on what we've observed from the development of new projects by munis, it seems as though there's a bit of risk aversion that remains from that experience. We don't feel the munis that are short are going to retire the facilities that they do have. The retirements that have been forced due to restrictions on air emissions, particularly those in the South Coast, they have already occurred. And many of the munis that have had to retire plants have reduced the subsequent increase in spot market exposure by building or applying for new facilities.

There are a couple of munis that are long. Their incentive, perhaps an incentive for them to continue to maintain the plants that they have is that if we go through 2000/2001 again it could turn out to be really profitable. Not that we think there's a real chance of that happening.

What you see now is a typical week in each quarter of 2003 for the aggregate of 13,800 megawatts of capacity. We being with Sunday morning at which point only 1000 megawatts is being generated. We go through Sunday afternoon where in 2003, in quarter three, which is the one line which stands out, the average generation during the afternoon of -- during the peak hours that were in the afternoon on Sunday, it was 4500 megawatts out of 13,800 megawatts of capacity.

And you can see that in an average week in quarter three in 2003 these aging plants were operating at about a 50 percent capacity factor in aggregate. They were generating 6500 megawatts or so throughout the week, and then declining again on Saturday.

The three lower lines are representative weeks for this set of generators for the remaining quarters of the year. You can't really read too much into whether quarter two is higher than quarter one, or quarter four is higher. Much of that depends on hydrology conditions.

If you look at a similar graph for 2002 the sort of rank ordering of the remaining three quarters is changed somewhat. But, the graph, itself, doesn't look substantially different.

While in a typical week in this summer these plants are generating only at about a 50 percent capacity factor, some weeks are hotter than others. And the blue line on this graph reproduces that typical week during the summer for these generators.

The red line shows what happened during the week in which they generated most. I believe this was the third week of July for 2003. And you can see that on Monday of that week for at least one hour we were looking at about 10,500 megawatts out of this aggregate capacity.

The lesson to be learned from this is that we do rely on these plants. The values in 2002 were actually a little higher for a number of reasons. These two lines aren't entirely representative of a typical year.

In the summer of 2003 it was, I think, the fourth hottest summer in the last 54, on average. Meaning that these plants were relied on a little more than they might have been in 2003, had we had normal weather temperature conditions.

The peak week, however, --

PRESIDING MEMBER GEESMAN: Now, Dave, --

MR. VIDAVER: Yes.

PRESIDING MEMBER GEESMAN: -- when you said the fourth hottest summer in the last 55 on average, then I'd be comparing that with the blue line on that graph?

MR. VIDAVER: Yes, sir.

PRESIDING MEMBER GEESMAN: Okay.

MR. VIDAVER: Yeah, the blue line in a normal summer actually would have been a little lower at temperature conditions, and the summer been average. The red line, however, would have been quite a bit higher.

The hottest day in the summer in 2003 was, let's see if we can keep this straight -- the coldest hottest day in the summer in the last 54 years.

PRESIDING MEMBER GEESMAN: Okay.

MR. VIDAVER: I'm quickly going to go through four graphs which compare quarter one in 2003 with quarter one in 2002. Quarter two, quarter three, et cetera.

Comparing the first quarter of 2003 with that in 2002 generation from these facilities dropped 37 percent. Basically in 2003 we didn't rely on these units nearly as much as we did in 2002.

From the generators' perspective, they didn't make as much money. Or, I guess more accurately, they lost more money. In quarter two, a 54 percent drop in generation. Quarter three, a 28 percent drop in generation. And finally, in quarter four, a 30 percent drop in generation from these units between 2002 and 2003. Very little of this can be explained by hydrology. It seems as though the large amount of capacity that came online between the summer of 2002 -- after the summer of 2002 explains the reduced reliance on aging power plants during 2003. We got LaPaloma, Elk Hills, Sunrise, a bunch of peakers, something else.

Another observation that's important here is that most of this decline was absorbed by aging plants that do not have RMR contracts. There was some decline in generation from RMR facilities, but the decline for aging plants that didn't have RMR contracts was on the order of 50 percent.

So, what will happen in 2004? I'm only going to guess, but I've got some guesses. I think we're going to increasingly rely on these plants in the summer of 2004. There have been no major additions since the summer of 2003 and we've lost 1100 megawatts of capacity to mothball status. I believe the ISO reports it down 100 megawatts of capacity year over year in the ISO-control area.

There's been an exceptional amount of new capacity built in the southwest in the last 18 months. And then much of it in the last 12. However, much of that capacity is stranded due to transmission constraints. We can't take advantage of the power in California. There will be hours in which we can do it, and then we'll probably reduce dependence on aging plants from an energy perspective. But from a capacity perspective the interties are more or less full from the southwest during the peak hours. And the additional capacity built in the southwest is of very little use to California during those hours.

There's been a reduction of the capacity on the DC intertie from 3100 megawatts to 2000 megawatts which will reduce the amount of energy that can be imported over the tie. During quarter three that line will be shut down for Q4, increasing our reliance on instate generation, and therefore on aging power plants.

We've witnessed higher than expected load growth beginning in fourth quarter of 2003 due to economic recovery. It's at the upper end of the range of plausible growth that we established last year in the IEPR. This is simply going to increase the amount of energy that's needed. Much of this is in southern California, this load growth. That will increase demand for energy from aging plants.

We've just learned from the Scripps Oceanographic Institute that above-average temperatures are expected this summer. And we've known for awhile that we have below-average hydro conditions in both California and the Northwest. I would like to make one comment about the latter point. This is an energy problem, not a capacity problem. We don't see any reduction in available capacity from the hydro systems in California or the Northwest until September. In September we think we're going to get about a 500 megawatt hit in available capacity.

But the below average hydro conditions don't create any capacity problems for June, July and August. They do, however, reduce the amount of energy that can be supplied by hydro facilities, and therefore increase our reliance on thermal plants --

PRESIDING MEMBER GEESMAN: When does the

DC line go down?

MR. VIDAVER: Mark? Yeah, it's --

COMMISSIONER BOYD: I've heard October.

MR. VIDAVER: It's going to go out entirely in October. But I believe no later than June 1st it'll be derated from 3100 to 2000 megawatts.

PRESIDING MEMBER GEESMAN: And I've heard that, as well. Is there some transition point, though, between that June derate and when it's completely taken out in October?

MR. VIDAVER: Yes, there is a transition.

PRESIDING MEMBER GEESMAN: We probably ought to nail those numbers and dates down.

MR. TRASK: They've been working on the line for quite awhile.

PRESIDING MEMBER GEESMAN: Right.

MR. TRASK: (inaudible) derating on and off (inaudible).

DR. TOOKER: Dave, I have a question. How much do you know about how hot the summer is supposed to be compared to historical records, et cetera?

MR. VIDAVER: First of all, they're

projections by climatologists, so they're subject to substantial error. I believe that Scripps has provided us with tersiles and probabilities of average peak temperatures, or average temperatures being located in those tersiles. To be honest, you'll have to ask Tom Gorin. We have a conference call with Scripps scheduled for Thursday. We can provide you that information.

From a capacity -- from a peak load perspective, I don't think there's a substantial influence. It's just there will be more hot days. I don't think -- I'm not entirely certain, but I don't think it really affects the likelihood that the peak is 44,000 rather than 43,000. It just increases the number of times your peak loads are liable to be over 40,000. This is something we can talk about with Scripps on Thursday and get back to you.

DR. TOOKER: Thank you.

MR. VIDAVER: Okay. So, what's liable to happen in the short run, here defined as 2005 and 2006, we foresee a substantial number of plant additions. About, over the two-year period, by the summer of 2006 we show as much as about 4600 megawatts in new capacity coming on in California.

Some of that is very very firm. The munis' share of it, SMUD, Cosumnes, Magnolia. Some of it is a little bit shakier, Palomar, for example. We should know within, I would say a few days, but maybe a few weeks before Palomar will be available in 2006. That's up to the PUC at this point.

Metcalf and Pastoria are two Calpine plants which we show as coming online by the summer of 2005. I've talked to our compliance office and they assure me that those dates can be met. Even in the absence of those two facilities coming online, we're still talking about 3100, 3200 megawatts coming online over the next two years, which is enough to meet load growth, but no more than that.

At the same time we're going to see Mojave go out at the end of 2005. We're going to finally retire Hunter's Point.

PRESIDING MEMBER GEESMAN: What's your '05/06 assumption on Hunter's Point based on --

MR. VIDAVER: Optimism.

PRESIDING MEMBER GEESMAN: Optimism about Jefferson-Martin --

MR. VINE: Jefferson-Martin will be

completed. And the other minor upgrades to the transmission system will be sufficient to allow the Hunter's Point to be taken offline and still meet reliability criteria for San Francisco proper.

There are few, if any, transmission upgrades that are going to reduce reliance on aging plants and load pockets. Please don't ask me to define that. I can take a stab at it if you like, but --

PRESIDING MEMBER GEESMAN: Stab.

MR. VIDAVER: A load pocket, I use it as synonymous with a local reliability area, which is the ISO defines as an area which has insufficient generation within a set of transmission lines that so as to allow both NERC-established reliability criteria to be met related to contingencies. And to mitigate market power.

Here we're talking about San Diego; we're talking about San Francisco proper; we're talking about the various sets of constraints in the Bay Area, the Oakland constraint that the Oakland GTs operate, et cetera; Humboldt. In short, we don't see any upgrades over the next year or two which will markedly reduce reliance on those plants.

PRESIDING MEMBER GEESMAN: Other than Jefferson-Martin?

MR. VIDAVER: Other than Jefferson-Martin, yeah. And that will allow us to retire Hunter's Point. I'm not sure of how it will affect the way the ISO has to dispatch Potrero under RMR. My gut feeling is it won't have much of an impact, but I'm guessing.

PRESIDING MEMBER GEESMAN: And you've come to that conclusion on the transmission upgrades after talking to the ISO and the utilities?

MR. VIDAVER: We have reviewed and talked to the ISO about the RMR needs in 2005. The utilities have submitted their five-year transmission plans. The ISO has come up with a preliminary list of RMR needs for 2005 that shows that on a statewide basis they actually need another couple hundred megawatts under RMR contract year over year.

It doesn't look as though anything that has an RMR contract is going to go off in 2005. The upgrades that would be necessary in San Diego appear to be major to the point that there is no upgrade that can be completed by 2006 that will reduce the need for RMR generation in San Diego.

What I'll get to in a minute is the biggest impact is going to be from new plants. Those turn out to be really the only alternative to reliance on these plants, to substantial reliance on these plants over the next couple of years. I'll get to that in a second.

There are no upgrades which will allow us to import more power from out of state, as you can imagine, in the short timeframe that we're talking about. And while demand side management and energy efficiency targets, which have been mandated by the EAP, as being used to meet load growth, we're talking about 8000 or 9000 megawatts of capacity here versus demand side energy efficiency targets which are in the -- and I'm only providing an approximation -- 1500 to 2000 megawatt range.

So even if we were to reach all these targets, and I believe they've been set for 2008, if we were to reach them as early as 2006, it would barely put a dent in our need for generation capacity in the next two years.

PRESIDING MEMBER GEESMAN: Now, your

conclusion about upgrades to access capacity from out of state, does that extend to east of the river upgrades, as well?

MR. VIDAVER: It's my understanding that there is no transmission upgrade on the bulk transmission system that can be put into place which will substantially increase the amount of power that can be imported from the southwest in the next two years.

PRESIDING MEMBER GEESMAN: Okay.

MR. VIDAVER: I want to briefly go over the revenue sources for aging plants, because it's ultimately that source of revenue and its certainty that is going to influence whether or not these plants stay online.

We have -- I'm going to go to the second bullet first -- about 4000 megawatts of the 13,700 in our group that have RMR contracts. As an aside, the one-year term of these contracts really doesn't encourage maintaining these plants to the point that they'll be able to survive for a long time.

Major capital upgrades, under the assumption that RMR contracts will cover them, are very very risky. Most developers have said that they are reticent to undertake major capital upgrades based on the assumption that they're going to continue to have RMR contracts going forward.

PRESIDING MEMBER GEESMAN: Then how would you distinguish major capital upgrades from maintaining the plant? You used both phrases.

MR. VIDAVER: I'm not an expert on -- I don't fully understand the process by which the payment of capital upgrades are approved by the ISO and subsequently by FERC.

I understand that there are fixed revenue requirements, sort of going-forward capital costs that are filed by applicants for RMR contracts. And there are agreements as to the share of that going-forward capital costs that will be paid by the ISO. If the unit is deemed completely uncompetitive, the ISO will pay all of the fixed revenue requirement going-forward capital costs under the condition that the unit not participate on its own in ancillary service for energy markets. The unit's uncompetitive. If it can do that, it doesn't need all its going-forward capital costs paid.

The other contract type is one in which

the unit is competitive, at least during some hours of the year. It's allowed to participate in ancillary service and real-time energy markets whenever it wants to. But in this case only a share of its going-forward capital costs are paid. This is negotiated, this is pursuant to negotiations between the ISO and the generator.

Beyond that there are such major upgrades that cannot be completed in the course of the one-year contract. For example, SCR installation. It's this kind of upgrade that the generator is very reticent to undertake, because the -- and I don't want to speak out of turn because I don't fully understand the details yet, but if the upgrade is not completed by the time the contract expires, or is not renewed by the ISO, the generator is at risk for the unamortized portion of the cost of that upgrade.

Now, he can -- whether or not he's going to be paid for that unamortized portion depends on whether or not he plans on staying in business. If the contract expires and the generator then says, well, I think I can compete for at least a few hours a year and I'm going to stay online, the ISO then says, well, you're competitive; so, pay for the cost of your own upgrades.

The generator, in effect, to insure that he recovers the unamortized portion of the upgrade has to retire. Kind of a disincentive to keep capacity online.

PRESIDING MEMBER GEESMAN: Now these units have all been retrofit with SCR, haven't they?

MR. VIDAVER: Yes, every single unit that we're studying has undertaken -- look at Matt, make sure it's right -- which one are we missing? Oh, Potrero is about to undertake SCR. Potrero is needed for reliability. And in the absence of Potrero 7 being built like really soon, it's going to have an RMR contract for the indefinite future, until another facility is built in the Bay Area proper, or they add more transmission capability to Jefferson-Martin than they anticipated.

PRESIDING MEMBER GEESMAN: So, excluding SCR, what would you see then as a typical major capital upgrade?

MR. VIDAVER: That's a question that I don't have the information to answer.

PRESIDING MEMBER GEESMAN: Okay. I'll

pose that to the generators.

Are you aware of any major capital upgrades that have not been made in recent years because the one-year RMR contract does not encourage those investments?

MR. VIDAVER: My only anecdotal knowledge is the type of emission control installed by Mirant on Contra Costa 6 and Pittsburg 7, was not SCR. I assume because of the cost. They installed an emission control that's just enough to get them through 2004, and may or may not allow them to operate at full load in 2005 and beyond.

I'm sure that Mr. Blue may have more than anecdotes in --

PRESIDING MEMBER GEESMAN: All right.

MR. VIDAVER: There is one DWR contract which is unit contingent, and at least to the point that it seemingly requires the units to stay online for the duration of the contract. This is the contract between AES and Williams, which is then sort of effects a DWR contract between Williams and San Diego.

We've talked to AES and San Diego and they have told us that -- both parties have told us that they fully expect these units to be available for the duration of the contract.

PRESIDING MEMBER GEESMAN: And are those the units at Huntington Beach?

MR. VIDAVER: That's one unit at Huntington Beach, one unit at Redondo Beach and three units in Alamitas.

PRESIDING MEMBER GEESMAN: And how long does the contract run?

MR. VIDAVER: It guarantees the availability of these units through the end of 2010 for roughly 1000 megawatts of the capacity; I believe one of the Alamitas units comes off, as it were, at the end of 2007.

PRESIDING MEMBER GEESMAN: Okay.

MR. VIDAVER: The prices in the real-time energy market in nonsummer months are below the operating costs of most aging plants. The implications of this are twofold. One is that these facilities are -- I don't know how to put this because I don't have any -- I have not looked at the data to verify it, but these generators in this position say they're losing money. I have no reason to doubt that, but I have no information upon which to comment on it beyond that.

The must-offer requirement pays variable costs, but to date has provided disincentives for participating and ancillary service markets. The ISO is rectifying this -- trying to rectify this as we speak. It's proposed modifications to the appropriate tariffs at FERC which will allow units under must-offer to pay to participate, at least in ancillary service markets.

PRESIDING MEMBER GEESMAN: And when would those changes go into effect?

MR. VIDAVER: I believe 60 days after FERC has approved the change in the tariff.

PRESIDING MEMBER GEESMAN: So, it's not something that goes into effect subject to refund; it awaits FERC's approval?

MR. VIDAVER: Yes.

PRESIDING MEMBER GEESMAN: Do you know if that's anticipated this summer or --

MR. VIDAVER: I'm not involved enough with FERC to know. I believe that there is general consensus on both the parts of the -- for both the ISO and the generators that this is a very good idea. And will improve reliability in the ISO control area. Whether or not that's sufficient to get FERC to approve it, I don't know.

PRESIDING MEMBER GEESMAN: Okay.

DR. TOOKER: David, you earlier talked about the fact that there's a great deal of certainty regarding muni projects coming forward, but not for non-munis. You mentioned a few. How are those new projects affected any differently than the existing plants in terms of the real-time energy market during nonsummer months in terms of covering their costs for making them competitive?

MR. VIDAVER: I think the relevant distinction is the guarantee that the munis have, that the cost of those plants will be recovered through rates. The merchant generator has no such guarantee.

If I were a municipal utility that was looking at over-the-counter forward prices right now, and was substantially short I might be very interested in building a power plant just to mitigate electricity price risk.

Whereas a generator has no guarantee that he'll recover a dime from what he builds unless he's signed a contract.

DR. TOOKER: What I'm trying to get at is what is convincing you that projects like

Calpine projects are, in fact, going to come online, notwithstanding market conditions.

MR. VIDAVER: I talked with the compliance office.

(Laughter.)

MR. VIDAVER: There is an agreement between the state and Calpine regarding the completion of several of Calpine's facilities. This agreement has been renegotiated several times, but currently it's my understanding from a -- I hate to say this, Commissioner Geesman will hit me -- a confidential source that Metcalf will make itself -- will be online by summer of 2005.

Now, if anyone in the audience has a better understanding of the contractual underpinnings of that assumption I would dearly love to hear it.

Regarding Pastoria, I have the word of the compliance office here. And nothing more.

So, to my mind, with the skills and information available to the compliance office notwithstanding, I wouldn't put Pastoria in what we euphemistically call the 75 percent probable category, if only for the summer of '05.

I understand that Calpine is obligated,

given agreements it has with its creditors, to
bring Pastoria online by a certain date, so I
hesitate to comment much further.

DR. TOOKER: Thank you.

MR. VIDAVER: Sure. Calpine is here.

PRESIDING MEMBER GEESMAN: Jack, do you
want to interject something?

MR. PIGOTT: Let me --

PRESIDING MEMBER GEESMAN: Come on up to
the microphone.

MR. PIGOTT: Let me address that this
afternoon --

PRESIDING MEMBER GEESMAN: Okay, that'd
be fine. The court reporter should reflect that
was Jack Pigott from Calpine.

MR. VIDAVER: Now, I don't have a slide
which says incentives to retire, and I want to
clarify that.

One of the smaller incentives to retire
that we've run across is that the ability to bank
emission reduction credits and use them at other
facilities is a function of how much you have
generated during the couple of years prior to your
turning in your permits.

So, if you anticipate very low capacity

factors for the next couple of years, it's actually an incentive to shut down your plant because you'll be able to bank the credits that you have based on the capacity factors that you've run at recently. So this is an incentive to retire, assuming you anticipate running at a low capacity factor in the next couple of years compared to what you've run at in the previous couple of years.

The bigger incentive to retire is the expectation that not only are you losing money now, but you're never going to make any. And I haven't put that in a slide because it just seems so obvious.

So, in that I have a slide detailing a number of incentives to remain online, I don't want anyone to believe that I or any of the staff here have come to the conclusion that aging power plants will remain online. So, let's clarify that.

The incentives to remain online include possibly higher prices in the near term due to a tightening supply/demand balance. We've observed in the over-the-counter forward market and given the gas prices on NYMEX that we're seeing implied heat rates in the 12,000 range for this summer, summer peak hours; 13,000 in summer '05; and about 12,000 for calendar year '06. This requires a caveat. The forward prices over-the-counter are more a reflection of what some of the more risk-averse players in the market are willing to sign -- more risk-averse buyers in the market are willing to sign contracts where the market's pretty illiquid.

So it doesn't necessarily mean that we can expect higher prices in the long run, at the levels the OTC forwards are trading at, which for summer '05 I believe is in the low $70 range. But it does indicate that the market in general thinks that things are getting tighter, especially south of Path 15 where most of these units are.

There's also a cost associated with retirement and it's not that easy to undo. If you find out you've made a mistake you have to leave with that, which provides some incentive for staying online until the amount of uncertainty regarding the future market conditions is reduced.

At the end of the energy crisis in 2001 staff noted that we had quite a bit of capacity and we could expect low prices going forward. But that we didn't think it would result in a substantial number of retirements because market structure hadn't been decided upon and that there was still a substantial amount of uncertainty. And it turned out we were sort of right. Most of the plants that retired did so because they were facing very high costs for emissions control upgrades. They didn't retire necessarily because they didn't see prices recovering. The exceptions being the plants that were mothballed by Etiwanda and the decision of Duke to mothball Morro Bay 1 and 2.

So there still is a substantial amount of uncertainty in the market which mitigates against retirement. The problem is that if these plants do retire the state, as noted, has few, if any, alternatives. So whereas the risk of retirement might be a little lower than I thought six months ago, the costs are nevertheless as high as ever.

The ISO expects to implement LMP in I believe 2006. The --

DR. TOOKER: Could you define LMP?

MR. VIDAVER: Locational margin pricing. The generators will receive prices established at the buss bar as opposed to zonal prices. Preliminary studies done by the ISO, I understand, indicate that units located near load centers are going to receive a premium. I'm not intimately familiar with these studies. This is one of the avenues we're going to go down over the next six weeks. So this is listed as only a possible reason that a generator might stay online.

Finally, the resource adequacy is going forward at a crawl. There's a possibility of contracts with load-serving entities pursuant to the adoption and implementation of formal resource adequacy requirements. And I'm going to discuss those in some detail.

These bullets probably aren't in the best order. As it stands now, IOUs and direct access providers, possibly, will be required to meet 15 to 17 percent planning reserve requirements in 2008. The interim requirements are yet to be determined. In fact, now 2008 is on the table. There are calls to move that forward to 2006.

PRESIDING MEMBER GEESMAN: I should add that Commissioner Peevey and I issued a joint statement at the procurement prehearing conference making just that call.

MR. VIDAVER: Nice to know I was right when I said that.

These load serving entities will be required to meet 90 percent of this requirement one year forward. Again, details regarding this are being hashed out at the PUC.

They are likely to be required to meet these requirements in each load pocket/local reliability area, which bodes well for aging power plants that are located in these areas.

Deliverability issues have yet to be resolved. There is a possibility that load serving entities will be allowed to credit such things as system power contracts with liquidated damages against this requirement.

On the other and there remains the possibility that those contracts will have to point to specific resources, and that those resources will be have to be deliverable. Meaning that they will have to be located where transmission guarantees that they'll be accessible to aggregate load. Meaning that more of those resources are likely to be in California than elsewhere.

All of these issues are being decided. In fact, they're being decided as we speak; hence perhaps the poor turnout.

The utilities, on the other hand, are increasingly short in capacity from the summer of 2005 forward. They are actually -- I have to speak in very general terms here because the details are unfortunately confidential. But they have issued RFOs. Edison has issued an RFO for the summer of 2004. I believe PG&E is expecting to do the same thing, although it may be for 2005.

The utilities are allowed to enter into five-year contracts with deliverability beginning in 2004. This is of significance because much of the uncertainty being faced by aging power plants can be alleviated by entering into a five-year contract. One-year contracts are fine, but three to five years gives you some degree of certainty; allows you to invest in maintenance and upgrades that you might, and I stress might, not otherwise enter into.

They may also enter into one-year contracts for delivery beginning in 2005 as long as it begins in the first three quarters of 2005.

Now, there's a difference between what

they're being allowed to do, and from publicly available information, what they are actually doing. Edison's RFO has called for three products. The first product is super peak capacity, which I believe is 5-by-8 -- eight hours during the weekdays -- for the third quarter of 2004. The second product is peaking capacity 6-by-16 for the third quarter of 2004. And the fourth product is peaking capacity 6-by-16 for year round.

As time goes by the expiration of existing contracts, notably DWR contracts, is going to result in a gradual increase in their need for capacity in other quarters, and an increase in their need for energy. As that happens the products which they will require will be increasingly in line with those that aging power plants can provide. And I'm going to get to that in a minute.

Edison has called for offers of capacity for a contract term of three years, which is two years less than the five years that they're entitled to. A stated reason for this is the uncertainty of their load obligations. As I'm sure you're aware, they believe that a resolution of core/noncore and CCA and all other load obligation issues needs to be undertaken before they can do least cost integrated resource planning.

PRESIDING MEMBER GEESMAN: My impression is the other two IOUs don't necessarily share that view.

MR. VIDAVER: I will admit to not having read every single filing in the procurement proceeding. A related reason why five-year contracts might be less than desirable from a utility's point of view, and again this is my own conjecture, is that three years from now the utility may have far more choices as to the asset or resource or provider than can provide the products that they need. They may feel that the market for those products is apt to be more competitive. And they may feel that they may be self-providing those resources three years from now, or maybe in a position to do that.

Again, this is just conjecture on my part, but it seems to be pretty common sense. So I don't want to attribute any motives to them that they don't necessarily have, but I get paid to think about things like this, for better or worse.

PRESIDING MEMBER GEESMAN: Do you have a sense of current market price levels for a one-year contract versus a five-year contract?

MR. VIDAVER: None whatsoever. That brings me to my next slide. The products being solicited by Edison today for peaking capacity are -- I should say the product -- is not one that aging power plants can easily provide. To the extent that I'm wrong I hope to hear about that from a generator.

But the fact that Edison is looking for quick-start dispatchable capacity eliminates a number of aging power plants; or at the very least requires that they operate 24 hours a day, every day of the year. Because they can't start up in 20 minutes.

As time goes forward and the utilities become increasingly in need of year-round capacity products, or perhaps more amenable to slow-start products, need energy products, the aging power plants will find themselves in a better position to provide those products and do so competitively.

The question then becomes two, three years from now what will the alternatives look like for the utilities. In the absence of new generation the existing aging power plants will be one of the few choices to provide these products. And the utilities will be purchasing them at the prices needed to make aging power plants whole.

I don't mean to imply this price is not competitive; it almost certainly will be. It's just a question of will there be other plants, new plants that can provide these products at a lower price. And I don't know enough about engineering to tell you whether if you built a new power plant of a certain type it would be able to provide a certain product that much cheaper than an existing steam turbine. This is something that I assume we will look into during the next six weeks.

And if a substantial number of new plants are not built will there be new contractual forms and products that the utilities will ask for that will reduce the cost to ratepayers of providing energy. Will the utilities make compromises regarding their need to have power available on 20-minute notice. Will contractual forms which allow slow-start units to compete for those products, and do so relatively efficiently, appear.

And that's a -- I guess all

presentations end with subjects for further discussion. And that's certainly one of the ones that we'll look at over the next six weeks.

PRESIDING MEMBER GEESMAN: I take it you would use the failure of Reliant to attract bids at their auction of Etiwanda and Mandalay last fall as a primary example of some of these uncertainties? Or just unattractiveness of the product to the LSEs?

MR. VIDAVER: That's a very good example, although I think 2003 was somewhat of an anomaly. Expectations regarding spot market prices in 2003 were that they were going to be pretty low. There wouldn't be a lot of risk in the spot market, exposing yourself to the spot market.

The other observation is in 2003 the utility have no resource adequacy requirement. It could choose between exposing itself in the spot market -- pardon me -- and signing a capacity contract. And given the market conditions in 2003, it no doubt deemed it quite reasonable to play the spot market as opposed to signing with Reliant.

We now have a situation where the spot

market is getting tighter; forward prices are getting -- or the market, itself, is getting tighter; spot prices are increasing. SB-15, for a variety of reasons, may be less reliable than we thought it was as recently as six months ago. And the utilities are now faced with resource adequacy requirements, if not for 2004, then for 2005, to book out this capacity in advance. It's a completely different set of circumstances.

PRESIDING MEMBER GEESMAN: So, in October of 2003 the utilities didn't foresee that they would have resource adequacy requirements imposed upon them. They did not find the Reliant auction attractive.

MR. VIDAVER: Well, they still don't have, for the summer of 2004 they don't have the adequacy requirements imposed on them as far as I can tell. I'm pretty sure that's right. I've been not getting a lot of sleep recently.

And I don't think they perceived -- at that point they didn't realize that 1100 megawatts of capacity -- 825 megawatts of capacity in SB-15 would be mothballed. They didn't realize that they would be facing much higher load growth during Q4 of last year and Q1 of this year.

So I think the market in SB-15 has gotten a lot tighter. And they may ultimately regret their decision -- they may now regret not having done that.

PRESIDING MEMBER GEESMAN: Is there an economic motivation from an owner of one of these aging plants to simply sell his gas supply and not bother with generating this summer?

MR. VIDAVER: Well, in the absence of an obligation to provide energy there is always that tradeoff, that if you can get more from the gas than you can from turning it into electricity, you're going to sell gas.

But the electricity price follows gas for that very reason. I think if we were to get to a circumstance where the gas market imploded and the price of gas started getting up again in the $20 or $30 range, but you had caps on the energy prices, you would see that problem.

I don't know enough about the gas market to know the likelihood of that occurring.

PRESIDING MEMBER GEESMAN: And you haven't looked at those numbers to determine where the cross-over point would be?

MR. VIDAVER: I admit to not being so

familiar with automated mitigated pricing and all the other soft price caps that existed in the ISO markets to know how soft they are.

PRESIDING MEMBER GEESMAN: Okay. Thanks, Dave, that was very good.

MR. TRASK: I will add a couple things. For instance, one of the generators told us that -- well, Reliant told us that they felt the main factor for not getting any interest in their capacity offer was actually the DWR contracts. That the utilities were locked into those contracts and were paying somewhat of a premium for that product. And until those contracts expire that they would probably not be too interested in signing any other contracts. They do start expiring this year, so just let you know what Reliant said on that.

PRESIDING MEMBER GEESMAN: And how rapidly do they fall off in southern California?

MR. TRASK: They, as I'm recalling just off the top of my head, they are phasing out in general over the next four years, and I believe it is pretty much the same increment --

PRESIDING MEMBER GEESMAN: Okay.

MR. TRASK: -- over that time. Probably

some of the generators can speak more authoritatively on that.

Next phase of our presentations here, I'd just like to talk about what we're doing on our reliability investigation for this study.

PRESIDING MEMBER GEESMAN: I want to go back, Matt, to that Reliant situation again. My recollection was that pursuant to whatever settlement agreement they entered into, they were, in essence, offering cost-plus capacity, is that right?

MR. TRASK: Right. As I remember they were saying yes, we're offering capacity about half the price of the DWR contracts, right at their cost, and still not getting -- did not get any interest expressed.

PRESIDING MEMBER GEESMAN: Okay. Thank you.

MR. TRASK: So we are conducting analysis of the effects of the aging plant retirements on the transmission system. We're doing that inhouse with our own transmission unit. And we're also coordinating with the ISO on one of their studies that turns out to be looking at pretty much the same issues, and I'll have Mark

Hesters talk about that in a minute.

One of the things that I mentioned earlier that we're looking at pretty strongly are the procedures that the ISO and other control area operators use to alleviate transmission circuit congestion in the Los Angeles area. Mentioned that before, that there's five or six interties going in; and depending on the loading or the combination of loadings on many of those interties, the ISO has a book of procedures where they'll go down and say, okay, with my loading combination here, I should use this plant to crank up within the load pockets and to help alleviate that congestion.

We're using that phenomenon in looking at those procedures to help assign, I guess, the importance of any of those aging units within the southern California area.

As Dave mentioned, we're also looking very closely at any project that could affect the RMR status of many of these aging units. It's pretty much a given universal theme we've heard from everybody, as long as the project has an RMR contract it will not retire.

Dave talked about some of the incentives or disincentives to invest in RMR units. However, if they are reasonably efficient we're assuming that they will stay in the market, or do the cost improvements that they need to do. It's the ones that are the least efficient that appear to be at risk for retirement after losing RMR status.

PRESIDING MEMBER GEESMAN: The ISO has not chosen to approach RMR on a multiyear basis?

MR. TRASK: Not yet. They're one year and one year only.

PRESIDING MEMBER GEESMAN: So, I guess if you could attribute a viewpoint to them it would be that the generators that are in the areas of likely to require RMR contracts for a period of years should know who they are and plan accordingly. But the risk of those plans being inaccurate would fall on the generators.

MR. TRASK: Right. For instance we've been -- Mirant has had quite a bit of discussions with us about the RMR status of the Encina unit. They I guess just generally assumed that if Otay Mesa and Palomar are completed, and the Jefferson-Devers, the transmission line down there is --

PRESIDING MEMBER GEESMAN: Rainbow Miguel? Valley Rainbow is gone.

MR. TRASK: Valley --

PRESIDING MEMBER GEESMAN: Mission Miguel is what's under consideration.

MR. TRASK: I will acquiesce to your expertise there. But, it's generally accepted that if those three things occur that the RMR status for Encina would be at risk.

Mirant counters that they -- well, they disagree. They feel that Encina will still be needed for local reliability effects, if for no other reason than black start capability for the San Onofre nuclear unit, which it does supply now. And according to Mirant, would be the only plant that could supply that in the future, as well.

It turns out that the ISO has started a study, it's actually a study they do every year, but this year they've added the importance of the reliability effects of the retirement of aging units. And it turns out that they are studying the exact scenarios that we're looking at. Mark will go into that in a second. The only issue there is that their study probably won't be completed until some time this fall, October, November region. It's taking a lot of input from the utilities, the exact kind of input we've asked from them directly. So we'll be coordinating gathering that data. And I'll let Mark talk a little bit about the specifics of the study.

MR. HESTERS: Actually with Matt's summary it basically took away everything that I was going to say that was important. But, the ISO and PTOs, Edison, San Diego and PG&E, do annual grid assessment studies.

Starting this year they've added a new element to those studies which is looking at the potential impacts of power plant retirements. These studies are usually -- they're supposed to be done in the fall; the schedules are a little soft. PG&E's current schedule is to be done in November. Edison and San Diego are just getting their study started for this year; and probably early next year is a better estimate for the timeframe on those.

The annual grid assessments, ISO stakeholder processes, they incorporate input from interested stakeholders. Those include utilities, generators, members of the public and other government agencies.

These are annual assessments. Up until this year they were a five-year study; then looked at a tenth year. They've actually just changed that I found out today. They're now doing the full ten-year study. They're looking at every year, not just five and a tenth. They're working at, for this year they'll be studying 2005 through 2014.

These assessments basically analyze the grid for reliability criteria violations. And I'll go into those real quick, just to summarize them. These criteria violations -- the reliability criteria are very specific about a couple of things. One is how you test for them, and what constitutes a violation.

The grid assessments in California incorporate NERC planning standards, WECC reliability criteria and the Cal-ISO planning standards.

As I said earlier and Matt has said, this year they've added a new element. They're going to actually be looking at what happens and what potential transmission or grid improvements are needed if certain power plants retire or not available.

The specific scenarios are actually on the next page. The whole new policy can be found on the website I have written down here. I'm not going to try and say that whole thing. But that actually, that site has the full policy for how the grid assessments will deal with potential new generators, generators that have retired or announced retirement, and generators that could potentially retire.

And the next two slides actually run through what those retirement scenarios are. I could either run through them, it's easy enough just to read them.

PRESIDING MEMBER GEESMAN: We'll read them.

MR. HESTERS: Okay. And that's all I have to say on this.

PRESIDING MEMBER GEESMAN: Mark, I have a question. What justification then does the ISO have for continuing to limit RMR contracts to just annual contracts?

MR. HESTERS: I don't know what their justification for it is. I imagine it's not wanting to be committed financially to something that may not be needed. But I don't know what that justification is.

PRESIDING MEMBER GEESMAN: It's the buy

high fear.
MR. TRASK: I'll go ahead and show the criteria here, or the scenarios that they're looking at, again they're the exact same plants we're looking at, San Francisco Bay and Morro Bay and Ventura; and then also South Bay and Orange County and San Diego.
I'd like to correct something I said before. Mirant has not purchased the Encina plant; that is still owned by Dynegy.
These are further on this study that show the units that they expect to remain available and unavailable. And we're using the same assumptions in our study, as well.
Okay. With that I'd like to shift a little bit into our investigation into the environmental and land use issues associated with the continued operation of these plants and the retirement of these plants. And first turning over an air quality discussion to Matt Layton.
MR. LAYTON: Good morning; my name's Matt Layton; I'm with the air unit in the siting division. I'm going to present some preliminary findings for the 2004 aging power plant study. These are based on meetings we've had with the

owners and also on some analysis, and also some work that we've done in the 2001 and 2003 environmental performance reports.

I got asked if I keep showing the same slide for a reason, but yes, I do. I just want to repeat that in California our generation system is relatively clean. This is in comparison to other states and other countries. We use a lot of natural gas, which is a very clean burning fuel; and also we have implemented a lot of emission controls and regulations that control those emissions from those generators. So, we do have a clean system.

And we expect the emission trends to continue; the system to get cleaner with the addition of new cleaner resources, these are natural gas fired resources. And also we still have a robust regulatory infrastructure that is going to make sure these units are controlled and remain controlled.

Regarding the aging power plants, the NOx emissions from these aging power plants have gone down 80 to 90 percent of the last ten years. This is because of the retrofit rules that were promulgated in the early '90s and are almost completely implemented throughout the state.

Most of these retrofit rules require an SCR on the units. There are some units that do not have SCR, Humboldt, Morro Bay, Coolwater do not have SCR, as David mentioned. One of the Contra Costa units and one of the Pittsburg units still do not have SCR. And Hunter's Point does not have SCR.

This is because the districts either did not foresee or require the NOx emission reductions that other districts did, and therefore did not require SCR. Or they allowed the operator, for example Morro Bay, to comply under a cap. So Morro Bay probably does not have to install SCR to comply with the emissions cap that they currently operate under. Shutting down 1 and 2, or mothballing 1 and 2 will help because it's a cumulative cap. And so if you have dirty plants like 1 and 2 operating, you'll approach the daily cap much quicker.

Also Hunter's Point, the way they are complying with the district rule is they are using interchange emission reduction credits. These are credits from past operation at less than average levels, bringing forward to apply to current operation. The owner of Hunter's Point believes they can operate out to 2007. Beyond that the interchange emission reduction credits, they probably do not have adequate credits to go forward. If they chose to operate beyond 2007 they would probably have to retrofit, or perhaps some rule change might be necessary from the district.

Regarding PM10 emissions, the cleanest burning fuel for PM10 is natural gas. We do not see any post-combustion controls on natural gas units to control PM10 any lower. Natural gas is considered BACT and BARCT, best available control technology, best available retrofit control technology, for PM10. If we were to look for PM10 reductions from the natural gas sector it would be very difficult because currently there are no technologies which can be readily added onto a natural gas burning unit to control PM10.

Similarly, our extensive use of natural gas in the state also limits the amount of global climate change gases that these units emit. This is in comparison to a coal plan which produces about two times as much carbon dioxide per unit of energy as a natural gas plant. And oil plants produce about 1.4 times as much CO_2 as a natural gas plant.

So many of the changes that -- if you were going to look at trying to reduce PM10 or CO_2 from the generation sector, you'd be hard pressed to find easy, simple reductions because we already have converted all the plants that burned oil at one time to natural gas, so there's very few simple easy reductions for those particular pollutants.

Despite having a very clean system California still has poor air quality in much of the state. And the progress we have been making is slowing. So we do expect that emission reductions will be needed in all sectors.

We would expect that all cost effective reductions would be considered, not just the easiest -- well, the politically easiest reductions.

So we assume that power plants will be required to provide some additional emission reductions to continue to improve air quality in California.

We've already seen the South Coast, they are considering modifying their BARCT rule, the best available retrofit control technology rule called reclaim. Trying to reduce those NOx allocations by 5 to 15 percent. They're negotiating with the owners of the facilities. The owners believe that at 5 to 15 percent they can comply with that reduction in allocation and not have to install any more emission controls than the SCR they already have.

The Air Resources Board last year did consider a model retrofit rule for combustion turbines. These combustion turbines were not considered in the previous round of retrofit rules. There were opportunities there. However, some of the turbines do not operate much. These are peaking turbines, and therefore whether or not the rules would be cost effective was debatable. But the Air Resources Board did not complete the rule development and so we don't see that coming down right now.

If aging power plants did retire there probably would not result in a net decrease in air emission in any one air basin. If a power plant retired existing ones would probably have to operate more to make up that. If a power plant did retire it would be able to supply offsets into the offset trading market to provide emission reduction credits for a new source. Potentially that could be a new power plant that would go into that air basin, as well.

And additionally, replacement units that do get built, the owner of that new unit might have a strong incentive to run the plant much more than the existing unit. Perhaps it would have a better heat rate and could compete more. So the retirement of a unit may actually shift generation into -- or replacement of a unit may shift generation into an air basin. So we don't see that the retirements will actually result in a net reduction of emissions in any one air basin.

PRESIDING MEMBER GEESMAN: Now, that's a pretty open-ended statement. You don't mean in just the near term. Your statement, as I read it, would apply for an extended period of time.

MR. LAYTON: Because the air quality is poor in California new units that would be built in those nonattainment air basins would be required to provide offsets. So, they would have to go out and find those offsets --

PRESIDING MEMBER GEESMAN: We got a whole bunch of them that we've permitted that already have offsets.

MR. LAYTON: Right.

PRESIDING MEMBER GEESMAN: So, let's focus the discussion on those as opposed to one that's not yet been licensed.

MR. LAYTON: Those emissions are already accounted for in the attainment plan. If you assume attainment by a certain date, you calculate the emissions that you know are out there; you also include all the emission reduction credits, because they will eventually be part of the inventory.

PRESIDING MEMBER GEESMAN: So that's how we're able to make that conclusion from a regulatory standpoint, but all of the members of the public that participate in our process never quite find that satisfying because they see the stack at the plant and they know every time the plant operates emissions are coming out of it.

MR. LAYTON: I think that's correct.

PRESIDING MEMBER GEESMAN: Okay.

MR. LAYTON: Dave Vidaver did mention that some of these aging power plants may have some incentive to retire now rather than later if they anticipate that they'll have a low capacity factor. This would protect their potential emission reduction credits.

Reclaim facilities, those facilities located in South Coast, do not have that same incentive, because the allocations are based on what is granted by the district, not necessarily by past operations. So the reclaim facilities would not have the same incentive to retire if they anticipated having lower capacity factors in the out years.

PRESIDING MEMBER GEESMAN: So that's any of the aging plants in the South Coast basin?

MR. LAYTON: Yes. I think there's one muni, the Grayson unit, is actually subject to rule 1135, but again, we've already said that we don't anticipate they will retire.

PRESIDING MEMBER GEESMAN: Right. Okay.

DR. TOOKER: Matt, if you take into consideration that the new plants are more efficient and the retiring plants, if they were to retire, have only limited emission reduction credits because they haven't operated very much, are you saying that that lack of offsets in terms of the quantity of offsets from retirement won't cover the total operating timeframe for the new plants? They'll have to go out and get more offsets from other non power plant sources, perhaps?

And that their increased operating time will more than displace the difference in efficiency of the new plant versus the old plant?

MR. LAYTON: Well, the difference in efficiency is probably pretty small. These aging units currently operate as peakers or mid-dispatch. If you were really going to replace it with a unit similar to that you would probably end up with a peaking turbine, which can have a heat rate similar to these steam boilers.

We all like to refer to the combustion turbine combined cycles as the best plant out there, but as David said, they don't operate very efficiently when they cycle. Their emissions go up with increased starts and stops. And also their heat rate degrades with stops and starts.

So, if you're going to put in a combustion turbine combined cycle and operate it at the non-optimum, you may not see much improvement over the heat rate or emissions rate compared to these boilers with SCR.

And, again, how a new plant would

operate, I really -- the owner may have a lot of incentives or different incentives to operate differently than the current owners. In talking to the owners of these current plants, because of the maintenance requirements some of the plants do operate for say, four months a year, and the other either months they have time to do maintenance at their leisure.

A new owner may not have that same opportunity. He may be under contract to operate all the time. And therefore, again, the capacity may go up with a new plant versus the old plant.

So the emissions are going to be different. But, realize that these existing units do have permitted emissions that are higher than their actual emissions. And that's actually -- in doing the attainment planning districts don't use the permitted, but they do some forecasting what the emissions might be. And they've sometimes been inaccurate in those estimations of how the emissions are in the out years. Because, again, the market's pretty volatile.

COMMISSIONER BOYD: A lot of subjectivity in this analysis, though.

PRESIDING MEMBER GEESMAN: A lot of

speculation.

MR. LAYTON: Well, yes. The aging power plants and public health. Air quality is a component of public health. Air quality depends on emissions, topography, and the climate. We also -- one of the things we'd like to study is what effect on public health would shortages of electricity or price spikes on certain markets have on public health, whether it's -- last summer there was a heat wave in Europe, and the number of deaths was incredible. So the reliability of the electricity market may have a bigger impact on public health than air quality.

Going back to air quality, regulators cannot really change the topography of California or the climate, but they can affect the emissions. And what we would hope is that the regulators go after the emissions that are most cost effective, where they can get the most bang for the buck, reduce the most tons for the dollars spent.

What I put three slides together on statewide PM10, 2.5. And I've highlighted up in the left corner the emissions from the electric utilities and the cogenerators, .75, 0.75 percent of the PM2.5 emissions in the state come from electric utilities. About half a percent, less than 1 percent come from cogenerators. That's a very small number.

PRESIDING MEMBER GEESMAN: And by electric utilities you mean the independent generators, as well?

MR. LAYTON: Correct. The new units, combustion turbine combined cycles that are online.

If we take that same PM10, PM2.5 and look at the Bay Area District, we see that the ratios are pretty much constant. The Bay Area has refineries, and so the cogeneration number goes up. Both the electric utilities and cogeneration PM2.5 contribution are less than 1 percent of the total.

And stepping further, we look at the City and County of San Francisco, those emissions there. Cogeneration drops, but the electric utility number goes up. But the total is about 1.4 percent of the total PM2.5.

So, in looking at the statewide numbers I believe we do actually capture what happens at an air district level or even a county level, because the numbers are representative. And, again, the numbers are very small. So, we would --

DR. TOOKER: What is the fuel combustion category? What's that made up --

MR. LAYTON: That would include other industrial combustion.

DR. TOOKER: Refinery?

MR. LAYTON: Refineries, unless it's a cogenerator. And sometimes the industrial codes get kind of sloppy. Some ends up in cogeneration in one basin, and another air basin it ends up in industrial.

But what's interesting about this, the way the Air Resources Board lumps these various categories, under miscellaneous they have a lot of different area sources. The area sources are hard to control, but they include residential fuel combustion, farming, construction, demolition, roads, cooking, waste burning.

Interestingly, in San Francisco, the City and County of San Francisco, farming constitutes about 5 percent of the PM2.5, about five times the electric utility PM2.5. And commercial cooking, the fast food facilities, are about eight time the tonnage from the electric utility PM2.5. Perhaps there could be more cost effective reductions realized from putting better controls on Burger Kings and things like that.

Again, the electric utilities are always easy targets because they are a single stack, single source. But they're fairly well controlled already. And, again, for PM10 and PM2.5, it's going to be difficult to try to get reductions from the extensive use of natural gas already.

So what we've seen to date is that the operation retirement of these units really has limited effect on emissions and air quality. We can't use much more natural gas than we do. There are some units that still burn fuel oil in emergencies only. And there's some smaller peaking units that do burn distillate.

Most of the units already have controls on them. And again, the aging power plant emissions are relatively small compared to other sectors in the total inventory.

PRESIDING MEMBER GEESMAN: I appreciate the PM2.5 charts you've done. Would you also prepare a NOx chart for us?

MR. LAYTON: The NOx charts show a similar trend. Yes. We have plenty of information on NOx.

PRESIDING MEMBER GEESMAN: Thanks.

MR. LAYTON: And the PM10 numbers are actually similar, but about half of the PM2.5. Again, the PM2.5, because it's --

PRESIDING MEMBER GEESMAN: It's more a combustion product.

MR. LAYTON: -- more combustion, therefore the utilities and the cogenerators actually have a higher proportion on that.

PRESIDING MEMBER GEESMAN: Sure.

MR. LAYTON: Thank you.

PRESIDING MEMBER GEESMAN: Thank you, Matt.

MR. TRASK: With that I'd like to shift to a discussion of land use issues, Eileen Allen.

MS. ALLEN: Good morning. In addition to talking about preliminary land use findings, I'll also be talking about once-through cooling, and touching briefly on environmental justice.

The major land use points that we've gathered so far are what I think you're aware of, that there's a great deal of community concern in San Francisco about the Hunter's Point project; and to a certain degree, concern about the Potrero project.

In 2001 the board of supervisors in San Francisco passed an ordinance regarding human health and environmental protections for new electric generation. Among other features the ordinance called for a formulation of a local resource plan with alternatives to fossil fuel generation. And that led to a City agreement with PG&E to shut down the Hunter's Point Plant when it was no longer needed for system reliability.

As Commissioner Geesman noted, there are a number of different perspectives on how the concept of local reliability is defined. In a March workshop one of the speakers mentioned the ISO's gold-plated reliability criteria, whereas there are a number of other perspectives that differ from hers. So, it's an area that will bear quite a bit more discussion, I think.

In addition to local concerns about the Hunter's Point facility, as I noted, some residents of southeast San Francisco have concerns about continued operation of Potrero, which is located approximately a mile away from the Hunter's Point area.

Recently the City and County of San

Francisco filed an application for certification with the Energy Commission to place three turbines on the existing Potrero Plant property consistent with the 2001 ordinance. So that's a project that's underway in the Commission's siting process.

PRESIDING MEMBER GEESMAN: Yeah, Commissioner Boyd and I are assigned to that case, so we will shortly be learning more.

MS. ALLEN: As you can imagine, given the ongoing interest in the two existing plants, Hunter's Point and Potrero, there's quite a bit of local interest in the City's plans for the three turbines being placed there. So we anticipate that that will be a stimulating process.

Moving to the idea of community planning processes such as general plans and local master plans, we've learned in discussions with the cities where these aging facilities are located that the two most active community planning processes are in Redondo Beach and Chula Vista. I didn't realize this was broken up into two slides. Thanks, Matt.

In 1992 the City of Redondo Beach had a specific plan process that discussed an eventual conversion of the waterfront area to non-industrial uses. Through a number of local participants and stakeholders they shifted to a different vision in 2002 that retained a number of industrial uses, including the Redondo Beach plant. And had an interesting mix of things like movie theaters, a hotel facility and some residential quite close to the existing power plant there.

In the last year or so, without focusing on the power plant specifically, the 2002 specific plan went into litigation. Eventually the City rescinded that plan and at this point the 1992 specific plan has gone back into effect. The bottomline here is that Redondo Beach is in somewhat of a flux state as far as what to do with the overall area of the waterfront and the harbor area called King Harbor.

The new city planning director for Redondo Beach contacted Matt recently. We've talked to him. He indicated that he was looking forward to talking with AES over the next few weeks and months about how they saw their plant fitting into the City's vision. So we look forward to hearing more about discussions there.

PRESIDING MEMBER GEESMAN: Is the plant in the coastal zone?

MS. ALLEN: I think it's just outside of the coastal zone.

PRESIDING MEMBER GEESMAN: Okay. And I believe Redondo Beach was one of the AES units identified as likely, under the DWR contracts, to continue in operation during the full duration of our study period?

MS. ALLEN: That's our understanding. As far as the 1992 specific plan we haven't been able to identify any sunset dates or timeframes associated with the idea of a conversion to no industrial in the waterfront area. So, I think that's something that the City hopes to work out with AES as to how long they intend to run that plant.

PRESIDING MEMBER GEESMAN: Now, would I be correct in assuming that the cooling water intake is, in fact, in the coastal zone?

MS. ALLEN: Yes, it is.

PRESIDING MEMBER GEESMAN: Okay. So, that part of the structure would be a part of the local coastal plan?

MS. ALLEN: Yes. And the City, as the

lead agency for the local coastal plan, would be addressing it in that context, as well as the Coastal Commission having some input there.

PRESIDING MEMBER GEESMAN: Yeah, an amendment to the local coast plan would require going back to the Coastal Commission, would it not?

MS. ALLEN: I think so, yes.

PRESIDING MEMBER GEESMAN: Okay.

MS. ALLEN: Moving to the San Diego area, the City of Chula Vista and the Port of San Diego are jointly working on a Chula Vista bayfront master plan with Duke's South Bay Plant included. The last word we had from the staff person at the Port of San Diego, which is the landowner, and Duke is a lessee, the Port of San Diego is that they haven't identified any alternative sites in the immediate area that they think would be superior to the current site where the South Bay Plant is.

I asked him whether they were looking at any sites outside of the immediate waterfront area. For example, whether there would be room or feasibility for another plant in the Otay Mesa area, and we know there are transmission constraints there. And then there may be air quality offset challenges.

His response was that all of those were factors, but they were also looking to make use of the existing infrastructure, as far as gas sources and transmission connections that were right there in the waterfront area. So, as of last month, they were still looking at that general area in terms of possibly repowering, or possibly a new facility sometime in the future. But, they anticipate that there will be some months into perhaps another year of community discussions, the master plan process.

PRESIDING MEMBER GEESMAN: And are they -- is Duke under any kind of sunset agreement? The term of their lease.

MS. ALLEN: We have seen numbers that indicate the lease would be up in 2010. I asked the Port Staffperson about this, and he said that that was under discussion.

DR. TOOKER: Eileen, in any of these discussions has there been any indication of an interest in discussing potential futures for desalination facilities?

MS. ALLEN: Not that we're aware of in

Chula Vista. We've heard about that as a possibility for the Encina plant. Possibly in Huntington Beach. Possibly in Moss Landing. And then there's a fourth one that's in there as a possibility; I'll have to check with Matt.

Okay, I can get back to you on a fourth possibility. But, I'm not aware of that possibility associated with the South Bay plant.

PRESIDING MEMBER GEESMAN: Thank you. And the South Bay plant, would that be in the coastal zone?

MS. ALLEN: Yes, it is.

Moving to once-through cooling. Approximately four-fifth of the power plant units that we're studying are once-through cooled. For the most part, they are in the coastal zone, with a few that are set back like Alamitos and Haynes, that are away from the coastal zone, but they're drawing coastal waters out. So they're considered to be part of the coastal group.

Looking at a definition of once-through cooling, that would be a plant that withdraws water for cooling the turbines from an adjacent water body, such as a bay, river or ocean; and then often discharges that heated water into that same body of water.

There are new federal regulations as part of the Clean Water Act that are going to affect once-through cooled facilities. These are primarily through something called section 316(b). And these were released in February 2004 to establish the best available technology for protecting aquatic species. The new regs require impingement impacts to be 80 to 95 percent lower than uncontrolled level.

If you're like me and you need a refresher on what impingement means, that's trapping the aquatic organisms against the cooling water intake structure so they might be caught against the screen. Whereas, entrainment is the overall pumping mechanism drawing the aquatic organisms into the cooling system.

As noted here on the slide, the new regs require entrainment impacts to be 60 to 90 percent lower than uncontrolled levels. And the regs provide compliance alternatives and choices such as the use of existing technologies, selecting additional fish protection system technologies; and then habitat restoration options.

Since these regs are quite new, we

expect there will be a considerable implementation process where it will take awhile to work out how it's actually put into effect. Any generators who are here today may be able to offer their perspective on that.

PRESIDING MEMBER GEESMAN: The habitat restoration provision, though, has been challenged in the Second Circuit Court of Appeals?

MS. ALLEN: I believe so. Dave Abelson, who has left the room -- oh, he's back? Okay.

PRESIDING MEMBER GEESMAN: Can you address that quickly, Dave?

MR. ABELSON: Thank you. My name is David Abelson; I'm Staff Counsel at the Energy Commission.

My understanding is that there were two sets of regulations that have come out from EPA. One covering new facilities, which has been out for a couple of years. They were challenged in court on a variety of grounds, one of which being that they allowed offsite mitigation for new facilities. The Second Circuit did rule that that was impermissible under the provisions of the Clean Water Act.

The court also indicta said that it felt the same would be true for regulations concerning existing facilities which had not issued at the time. But as Eileen is indicating, have issued as of February of this year. Those newly issued regulations for existing facilities do also allow habitat restoration as one option.

The parties that have sued have already filed notice that they will be raising that issue in the courts again with the same outcome sought, namely that only technology fixes at the source are allowed under the Clean Water Act.

So, we'll have to see what the courts actually say on that.

PRESIDING MEMBER GEESMAN: And at this point the Second Circuit decision is simply indicta as it relates to existing facilities?

MR. ABELSON: As it relates to existing facilities, that's correct. But, again, I think it's important to recognize that the same parties are basically pursuing that litigation as we speak in that circuit now that the existing regulations have been issued.

PRESIDING MEMBER GEESMAN: Technically the Ninth Circuit would have to consider itself bound by the Second Circuit decision?

MR. ABELSON: To be honest with you, Commissioner Geesman, I'm not sure about the relationship of the two Circuits when it comes to USEPA nationwide regulations. I don't know whether the DC Circuit has exclusive jurisdiction on that issue or not.

PRESIDING MEMBER GEESMAN: Okay.

DR. TOOKER: David, are the new regulations currently applicable to existing facilities?

MR. ABELSON: The problem, Chris, is that we're all a bit casual in our use of the terms. If by the new regulations you mean the one that were issued on February of 2004 --

DR. TOOKER: Correct.

MR. ABELSON: -- is that what you mean? The newly issued regulations?

DR. TOOKER: Correct.

MR. ABELSON: Those expressly deal with existing facilities. There were previous regulations issued about a year and a half or two years ago that dealt exclusively with new facilities. And those were the ones that were challenged and the habitat restoration was declared illegal.

DR. TOOKER: What I'm trying to understand is what is the impact of these new regulations on existing facilities, i.e., with respect to retirement options. It appears they're the factors here that challenge the economic viability of these units going forward, and this would appear to me to impose additional economic liabilities on those units to continue to operate.

MR. ABELSON: Well, I don't want to represent that I'm any expert on this, but my understanding is as follows. Basically all facilities operating in California that require NPDES permits need renewals intermittently, I believe on average it's once every five years.

When they come before the Regional Water Boards for those renewals they are subject to whatever the then existing regulations are.

So, your point, Chris, would be correct that if these regulations take effect, which they have done, if they're upheld by the courts, which we don't know what the status of that will be, facilities that currently exist will periodically over the next few years have to take into account these regulations.

There is one piece, however, in Eileen's summary that's missing which is that there is a provision in the regulations that says that if the cost of basically achieving the performance standard she's outlined is wholly disproportionate to the benefit to the fishery then essentially you can get out of the deal entirely.

DR. TOOKER: I had one other question and perhaps Eileen can answer this. Are those percentages annual percentages?

MR. ABELSON: Quite honestly, Chris, I do not know the answer to that. There are many issues on these regulations that are just beginning to be discussed, including what the term uncontrol levels means, what the 80 to 95 percent references specifically, and the Water Boards and EPA undoubtedly are going to be working that through over the next few years.

DR. TOOKER: Okay.

MS. ALLEN: Chris, I was going to say much the same thing, and particularly highlight the ambiguity of the phrase uncontrolled levels. And, indeed, when you start measuring it is part of that uncertainty.

PRESIDING MEMBER GEESMAN: You had another slide?

MS. ALLEN: Okay, I went to this next slide in part because of your question, Chris. In our talks with the generation owners we haven't heard anybody saying that the new regs were going to lead to closure of a facility for that reason. We also haven't heard of anybody saying that they intend to stop using once-through cooling.

They have told us that they intend to do whatever the new regulations will require as far as compliance. At this point it's pretty uncertain how the Regional Water Quality Control Boards are going to apply the new regulations.

I expect it will be an ongoing discussion and perhaps some trial and error with the generators and the Regional Boards. But at this point we haven't heard of it as a prohibitive factor.

PRESIDING MEMBER GEESMAN: Have you got a timeline of when these different plants come up for their next NPDES permit?

MS. ALLEN: Our biologists are saying yes. Yes, we do.

PRESIDING MEMBER GEESMAN: Okay, that would be useful to share with the Committee.

MS. ALLEN: Okay. Briefly, I'll go back

to this slide that just gives some technical material. Water intake velocities are currently higher than the new regulation standard of .5 feet per second. The current entrainment and impingement impact analysis are now out of date. And I said current, they are no longer current, or they were never actually done for some of the older facilities.

On a local basis, as far as the Santa Monica Bay, there have been no cumulative impact studies completed for the array of power plants in that area.

We've heard from some parties that as commercial fishing is currently restricted in some areas, there's some belief that if some of these existing plants were modernized and there was less entrainment and impingement, that that might ease some of the policy restriction on commercial fishing. We need to spend more time thinking about that and researching it, but it's possible that there could be a commercial fishing benefit.

We talked about this. I think the bottomline is the uncertainty on how the Regional Boards are going to apply them at this point. We can get back to you on the schedule.

Looking at examples of -- preliminary examples of environmental enhancement activity that the power plant owners are doing, Encina, through NRG and Dynegy, is involved in a program for dredging the Agua Hedionda Lagoon in the Carlsbad area with about $2 million spent every two years for keeping the lagoon open. And this is done because it maintains water quality and benefits associated with the bird and the endangered California least tern and its habitat.

NRG/Dynegy also supports a sea bass hatchery operation in the lagoon, and supports restoration of eel grass habitat and elimination of a variety of invasive species in the lagoon. So the lagoon is really a significant extension of the power plant property.

Moving to a Reliant facility at Ormond Beach, Reliant has told us that they're a partner in efforts to restore the Ormond Beach wetlands. They are involved in supporting a marine laboratory that's raising abalone. They've put up signs to help protect the endangered California least tern and the threatened western snowy plover.

Diverging in a slightly different

direction, the Ormond Beach facility is involved in proposals for the onshore facilities for LNG terminals. There are two offshore LNG facilities that are proposed off of the Ventura coast. And one of them would have a pipeline coming into shore right here in the Ormond Beach facility. So that isn't related to environmental enhancement, but it is in the category of another project that we're aware of as a possibility in the Ormond Beach area.

PRESIDING MEMBER GEESMAN: The only onshore facility would be the pipeline, would it not?

MS. ALLEN: That's right. Well, perhaps a very small compressor-related station.

Moving to environmental justice, very briefly, it involves a principle of assessing whether there's a fair treatment of people of all races, cultures and income. This is consistent with Resources Agency policy.

For purposes of this study we'll be looking at demographics of the population within two miles identified; and demographics, we're looking at income levels, and then do a breakdown of people of color. This is just one of many factors considered in the aging power plant study, but it is an important one, given the public interest.

PRESIDING MEMBER GEESMAN: Now, do we use a different radius in our siting proceeding than two miles?

MS. ALLEN: In the siting cases we generally go out as far as six miles, which is consistent with air quality analysis.

PRESIDING MEMBER GEESMAN: Why wouldn't we do that here?

MS. ALLEN: I'm going to defer that question to Dale Edwards.

MR. EDWARDS: This is somewhat flexible at this point in time. It's our desire, staffwise, to move towards a smaller distance than six miles. And for this particular study we thought it might be appropriate to do that, to come down to two. But we're open to suggestion or compromise on that.

PRESIDING MEMBER GEESMAN: I think you ought to do the same as we've been doing in the siting cases. I think you'll find it much more acceptable outside the Commission if you maintain the past practice.

MR. EDWARDS: Not a problem.

PRESIDING MEMBER GEESMAN: Thank you.

MS. ALLEN: Dave, thanks for speaking up about the legal features of the new once-through cooling regs. Are there any other questions for me? Okay, thanks very much.

PRESIDING MEMBER GEESMAN: Thanks very much, Arleen.

MR. TRASK: I want to apologize for going well over our allotted time here. I think it's good proof that we really like to hear ourselves talk.

Just to wrap it up here, I want to talk a little bit about the remaining steps to complete the aging power plant study.

We've issued data requests to the California ISO and to the generators, themselves. We are also digging deeply into the FERC databoards to get quite a bit of cost and operational -- cost and revenue data. We found out that a lot of the information we need is filed with FERC on a public basis.

As I mentioned earlier we're digging very deeply to try to find anything that might affect the RMR status of any of the aging plant units, either due to a new plant construction or a transmission line project or upgrade.

We are going to classify our 50 units in the reliability study list as either high risk, medium risk or low risk of retirement. And analyze the effects accordingly.

I mentioned this earlier that we are doing systemwide --

PRESIDING MEMBER GEESMAN: Can I back you up a minute?

MR. TRASK: Sure.

PRESIDING MEMBER GEESMAN: How do you envision making that classification?

MR. TRASK: It's based on a lot of things. Starting with, of course, statements from the generators as to whether they're going to retire or not.

There's some fairly common sense criteria that we can use, for instance, if there are no other units at a specific plant, or all the units at that plant are aging and inefficient, we figure that's a relatively higher risk of retirement than if there are new efficient units at that plant. In other words, it's more likely that they would repower the inefficient units than to shut them down in those cases.

Of course, RMR status, whether or not there's anything out there that might affect that RMR status. Be very low risk if we can't find any project or transmission line that might affect that RMR status.

Contracts. For instance the AES units contracted to Williams for the DWR contract with SDG&E. Contract term there is well beyond our study period, so we're classifying those as low risk.

There's others that we still haven't quite made the determination. Basically we're trying to put ourselves in their shoes, in the generators' shoes, to look at all their costs, all their revenues, look at all the things that might happen in the next few years that would change the economics of aging plant operation, and then therefore their decisions on whether to retire or mothball.

One thing we have determined that it's fairly low likelihood that they will mothball as compared to retiring. And I think Dave covered that well earlier.

DR. TOOKER: Matt, are you going to be

including in this discussion about risk any potential for the ISO changing the criteria it uses for determining RMR contract, the need for contracts and the length of contracts?

MR. TRASK: We brought that up with the ISO and their initial response was that they don't foresee anything in the next four years that would change that, but there's probably as much uncertainty of that as there is in just about the rest of the industry. So it is subject to change, but as far as we know there's nothing on the horizon.

DR. TOOKER: Thank you.

MR. TRASK: As I mentioned earlier, we're going to be examining the low reliability effects using our own transmission modeling, the PSLF modeling. And also looking strongly at procedures that the ISO and control area operators use to relieve congestion in the L.A. basin. We're finding that's a very good source of information about the importance of these units.

And then we'll be completing our analysis of the environmental and resource effects of continued generation.

One thing that we are doing is an

appendix that will have a section on each of these plants, the 24 plants in our studies. And that will include a general map of the area, an aerial photograph, a map of the demographics of the area for the environmental justice concerns, as well as physical descriptions of all the units, their cooling systems, things like that. So it will be more or less a primer for each one of the individual plants in our study.

We're continuing our meetings with our generators and the agencies. We're generally having two or three meetings with each generator. First one sort of setting up the process; second one to really start the information exchange. And we anticipate other meetings just to make sure that we still understand what they've told us and that it fits our needs for our analysis.

We expect to conduct at least two additional workshops. One right about when we're completing our data collection process and coming to the draft form of the study in late June. And one after we release the APPS in late July. And as we discussed this morning, perhaps one in as little as two weeks from now.

Following those workshops we intend to

revise the study and publish it in its final form for the 2004 IEPR update.

And that's it. We had planned to open the floor now for public comment and for presentations. The only other presentation I know of is Dynegy would like to do that. And they think that would be more appropriate during one of the panel discussions. Yeah, Greg.

MR. BLUE: I have a suggestion for the afternoon session. Since some of the panelists are not here -- that all people that are here just come up --

PRESIDING MEMBER GEESMAN: I think that's a great idea.

MR. BLUE: -- go through all the questions, you know, and --

PRESIDING MEMBER GEESMAN: Yeah.

MR. BLUE: -- referring to -- will join us, as well. They weren't invited, but they'll participate with this.

PRESIDING MEMBER GEESMAN: Good.

MR. TRASK: They were invited. Everybody was invited.

PRESIDING MEMBER GEESMAN: Well, they're re-invited.

MR. BLUE: And accepted.

PRESIDING MEMBER GEESMAN: Why don't we take a lunch break then and come back about 1:15.

(Whereupon, at 12:15 p.m., the workshop was adjourned, to reconvene at 1:15 p.m., this same day.)

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AFTERNOON SESSION

1:25 p.m.

MS. ALLEN: -- the Redondo Beach plant, whether it was in the coastal zone. That plant is physically located in the coastal zone. It's in an area which doesn't have a coastal plan implementation program right now due to the flux over the city's plans for the pier and harbor area. But, yes, it is in the coastal zone.

During the lunch hour I looked at a chart that showed other development projects in the area of these plants, and indeed, South Bay does have a desal possibility. So, thank you for those corrections.

PRESIDING MEMBER GEESMAN: While we're in that spirit, I think we had a discussion on the DC line where I believe it was said that it had been derated down to 2000 megawatts. And it's my understanding that's the way the ISO has, in fact, been showing it for this summer. But, it's actually been derated to 1400 megawatts. And if you look at the WECC website today it's currently at 1370. So I think we need to correct that.

MR. TRASK: So noted. Okay, well, what we're planning this afternoon is a series of panel discussions. Because there's so few people here I'm actually proposing that we all become the panel for as many of us to sit up front here as possible. And whenever you have a desire to ask a question or participate, if you're not sitting up front here, we ask that you come up to the podium there so that we can have it for the court reporter and the broadcast on the internet.

And I'm also proposing to change the order of the panel discussions since Tim Hemig, one of the people who wanted to participate in the environmental panel has to catch a plane here in about 45 minutes.

So, with that, I'd like to get folks to come on up here. Just be mindful that whenever you speak you need to speak into a microphone.

PRESIDING MEMBER GEESMAN: The microphones are on when you see the green light.

MR. TRASK: Well, maybe to get things going here, Greg Blue would like to do a presentation.

MR. BLUE: My name is Greg Blue with West Coast Power. West Coast Power is a joint venture, 50 percent owned by Dynegy and 50 percent by NRG Energy.

First of all I want to thank the panel here, the Committee for allowing us to participate. I think it's been a good process so far. I prepared the presentation in advance of -- I did not see the questions that were going to be asked, so in fact, one of the things you'll see, and I'm going to kind of roll through it pretty quickly, I will answer some of the questions. But look forward to further debate as part of the panel.

I'll say a couple of things. I think we're pretty satisfied, based on the staff presentation given this morning that we see a lot of the issues the same way as the staff does. What I'm going to do today is just briefly highlight what we said last time, because I've got some updates to what we said last time that I think are important for the Committee to hear.

As far as I wanted to just respond to a couple of issues from this morning that I heard questions asked by Commissioner Geesman and some others that I would recommend, and you may have already answered this, but when you get to the issue of defining local reliability and load pockets, I would feel very comfortable with what the ISO has to say on this matter. And I'm pretty sure that they have an answer for you whenever you get those guys here in the room.

Another issue that we're going to talk about a little bit further, Tim Hemig from NRG Energy is our environmental manager on behalf of West Coast Power; he's going to talk a little bit about this. But, Commissioner Geesman, you had asked as well what are some of the other large capital improvements that generators may be required. And one of them would be compliance with 316(b). And I'll let Tim talk a little bit more about that.

Another statement I make and I feel pretty strongly about this, that there will be plants that will retire that have not announced yet that are not probably -- people may or may not be telling you this, but I feel that there will be other plants that retire, not necessarily for the economics, but the fact that they are just at the end of their useful life. And they've become unsafe to run. And at some point, if they become unsafe to run, they'll be retired regardless of the economics.

PRESIDING MEMBER GEESMAN: Now when you

say unsafe, do you mean to the workforce?

MR. BLUE: Yes.

PRESIDING MEMBER GEESMAN: Okay.

MR. BLUE: Yes.

PRESIDING MEMBER GEESMAN: So you're not necessarily saying that they'd be unsafe to the non employee public --

MR. BLUE: Correct.

PRESIDING MEMBER GEESMAN: -- but you're worried about a risk to your workers?

MR. BLUE: That's correct.

PRESIDING MEMBER GEESMAN: Okay.

MR. BLUE: It's not necessarily us. I'm just saying --

PRESIDING MEMBER GEESMAN: No, I --

MR. BLUE: -- in general, out there. That's my opinion.

One other question you asked about the DWR contracts and how they start rolling off. And one thing we do know is that our contracts of about 2300 megawatts roll off at the end of this year. And that's going to increase the net short position for the two utilities down south.

Just briefly, this is what we said last time, and I'm not going to go through all this, but just highlighting the issues that are up there. We talked about this study needing to look at or make recommendations regarding capacity markets. And I'm going to talk about each one of these in just one second.

We talked about resource adequacy requirements and how important those were. Deliverability standards, I believe we had a little discussion about that last time. I'm going to talk a little bit more about that. Where we see things going on that.

We talked about grid reliability, and we think the ISO, again, should be identifying the plants that are needed for reliability, both, you know, local reliability as well as the whole grid.

One thing that we haven't seen to date in this, at least talked about in the report, are -- well, we haven't seen the report, but we have seen a focus on it in the presentations, is the redevelopment of new generation. And I'm going to talk a little bit about that, new generation on the existing sites.

We still believe that there should be a preference for redevelopment of existing sites, understanding that preferences aren't well liked in the Capitol. And we, since our last meeting, have come across some evidence of that. But we still believe that. We think that there are some benefits to that. And we think it should be a good public policy for California.

The last one --

PRESIDING MEMBER GEESMAN: Let me ask you, Greg, how would such a preference manifest itself?

MR. BLUE: I'm going to talk about that.

PRESIDING MEMBER GEESMAN: Okay.

MR. BLUE: A little bit later. And we can do some back-and-forth.

The last thing you can't see for some reason. I guess my stuff is too big. Time is of the essence.

The panel that I was on initially was looking at the plans, projects and things that affect the economics of the existing plants. And a lot of this stuff you've already heard this morning. So I guess, you know, -- this is currently, this is as of today, detriments to keeping the aging power plants in operation.

There currently is a lack of capacity market. The continuation of FERC-mandated must-offer mitigation in the long run is a deterrent. The one-year RMR contract, you've heard about those, potentially being a deterrent to the continued operation of these plants.

No deliverability standards. I'm going to talk about some of these in just a few minutes.

If we were to have locational marginal pricing, that would go a long way to sending the right price signals. But that's not going to be around for a few years. And as we stated earlier, our main concern is over the next two to three years.

Regulatory uncertainty. Well, I think we're much more certain than we were a year ago. There still is an amount of uncertainty. Alternate uses of property. Believe it or not, land use -- developers have been contacting some of us who have plants on the coast and they're interested in, you know, the land there.

We also heard about uncertain recovery of major maintenance and capital investments. We heard that this morning from the staff.

Some of the things we think are out there that need to be looked at, and that are happening, and I think that the long run things are getting better. And for the long term viability I see a lot of positive signs. But once again, concern about '05, '06, '07 timeframe, you know, assuming we can get some of that stuff in place, that will alleviate some of these issues.

But, the one thing that's out there is the proposed capacity tagging proposal by the Silicon Valley Manufacturing Group has led a coalition of folks. This is a potential tradeable capacity market idea. This is what's being rolled out today in San Francisco in the resource adequacy workshops. That's why a lot of people are there. That's going to be getting a lot of attention here in the next few months. And hopefully will get some consideration.

But, once again, the issue of capacity markets, I think, is an important one. We hope the aging power plant study will recognize that.

Resource adequacy requirements appear to be accelerating and resulting reserve requirements will create a market for intermediate and peaking facilities.

We need to see in the utilities' procurement plans a rounded portfolio that includes both long-term and short-term resources.

And we hope that that will be included in there. The short-term resources, when I say short term I mean three-to-five-year type contracts. Those are the type of contracts that existing facilities can expect to receive in the market. They're not going to give a ten-year contract to an existing facility, in my opinion. Maybe somebody will, but I don't think so.

(Parties speaking simultaneously.)

PRESIDING MEMBER GEESMAN: (inaudible).

MR. BLUE: -- will increase the value of existing capacity, we've heard that from the staff this morning.

Multi-year RMR contracts would allow for capital investments for major maintenance. And one of the things, we are pushing this issue at the ISO. So far we have not -- without success. But any help that the aging power plant study could give us on that would be, I think, appreciated.

Existing transmission capabilities is also something that we think is an advantage for some of the existing facilities and should go a long way to keeping some of these plants operating.

As I said earlier, time is of the essence. And a lot of this stuff, I think, was presented in the staff report. But I think we think that since this process, even this process here, of studying aging power plants just started, it's become even more critical for California to maintain existing generation.

We've got the ISO summer assessment report which indicates basecase, basecase not adverse case, we think we're in adverse case now due to load growth, but the basecase showed that reliable service may be in peril as soon as this summer. It's very thin. Safety net, or safety margin, as we call it.

Both NERC and the ISO have recently stated that load in California has increased 4 percent over last year. And I would call this unexpected increase. I'm not sure who forecasted -- I don't know if anybody forecasted this type of load growth. And the economy really hasn't even started recovering. And so that leads us to a concern about next year even.

PRESIDING MEMBER GEESMAN: Well, but you know, if my recollection is correct, our forecast, which anticipated problems in a one-in-ten weather scenario as early as 2006, assumed an economic growth rate of, I think, 3.3 percent. If, in fact, that economic growth rate were 4.3 percent, as I recall, it would add another 500 megawatts of demand in 2004.

And I believe 800 megawatts -- well, I'm sorry, I can't generalize beyond the 500, but I think that even as unfocused as our long-term forecasting tool is, when applied to a short-term timeframe, in looking at some of the parameters it's pretty easy to see where 4 percent load growth could jump up at us and surprise people.

MR. BLUE: Okay. The National Oceanic and Atmospheric Administration has shown that the snow pack is well below normal for California and the Pacific Northwest. There was a report out today, I think the California ISO market analysis has come out with a statement that was posted on the website today that California snow pack is at 50 percent of normal. Now, I don't -- this has been reported to me. I haven't actually looked at it, but that's the report that I received.

We look at hydro flows being low this year. And I know that as someone stated earlier, you're only talking about energy and not capacity.

However, lack of energy from the Northwest will cause the capacity to be called on in California.

Everybody knows about the stage one emergency load-shedding and service interruptions. So, it's very critical. This report is, I believe, becoming more and more critical. And I believe there's no other state agency that's looking at this situation as well as the California Energy Commission. And I believe one of the recommendations I would have is that we start some preliminary briefings with legislators as soon as possible on some of these issues, because they need to be aware of this.

With the current schedules they wouldn't get the report until later this year, at the end of this year. And my suggestion would be some preliminary briefings would not be a bad idea.

As I said, the CEC is the only state agency looking at this issue of both the aging power plants -- one of the things I want to make sure is that everybody's clear. I'm not sure that anybody's going to actually repower. When you use the word repower that implies you're going to repower one of the old turbines. And that's not going to happen.

What we're talking about is redeveloping a new generation plant on the site. When we say repowerings, we mean redevelopment. When we say redevelopment, you can use those words interchangeably, but what it means is building brand new generation on that site.

We think that some of these existing sites, there could be potentially lower delivered cost to the load centers. We believe that it can minimize environmental impacts; reduce pressure on the stress transmission system; and limit California's exposure as a net importer of power.

PRESIDING MEMBER GEESMAN: Not to get too hung up on nomenclature, but let me throw in two cents worth for repowering. When you use the word redevelopment I think in legal circles it raises questions that you're involving redevelopment agencies and tax increment financing. And that may cause more consternation than --

MR. BLUE: We have run across some of that. Even when you use the word brownfield.

PRESIDING MEMBER GEESMAN: Yeah.

MR. BLUE: There's some issues there.

PRESIDING MEMBER GEESMAN: Yeah.

MR. BLUE: With power plants or other development. However, we keep hearing a lot of people, both regulators, policymakers, staffers, talk about repowerings, and then they talk about repowering the older units.

PRESIDING MEMBER GEESMAN: Right.

MR. BLUE: That's not going to be.

PRESIDING MEMBER GEESMAN: Right.

MR. BLUE: Resource adequacy, this is a very important issue that --

UNIDENTIFIED SPEAKER: I want to come back to --

MR. BLUE: -- I think is accelerating in implementation of some of this stuff. The current schedule was for it to be phased in by 2008. But what's recently happened is both the Governor's Office and President Peevey at the PUC have expressed concern that it's too slow. And they both stated they would like to see this in 2006.

Last Friday the Western Power Trading Forum filed a petition for modification at the PUC of the January 22nd order, which we called for the 15 to 17 percent reserve margins to be effective May 1, '06. That's the defined summer period by the PUC.

We also called for the requirement for the utilities to use best efforts to comply in 2005. We did not define best efforts. Leaving that to the PUC to decide.

This is a very important issue. I think a couple of things. What's happened in the debate now, in the 15 to 17 percent, has all of a sudden become 15 percent. And everybody says, well, we're just going to go for 15 percent.

If you were to ask the ISO this question, is 15 percent enough for California's system you might get an answer that would surprise you. I think they don't think that's -- even the ISO Board Member Mike Florio at the last ISO board meeting was questioning whether 15 percent is even enough for California, based on the hydro and the imports and the type of peaking system we have.

So, we're hopeful that this issue gets heard and gets -- I feel pretty confident that this is going to be accelerated, which is one of the things we had said, is a good thing for some of these existing units. And, once again, heading in the right direction in the long run.

Capacity markets. We think that capacity markets are needed in California for a couple of reasons. One, as we heard today, the spot prices are not enough to recover your full cost. And you need some sort of a capacity payment, either through a bilateral capacity contract or in the form of a tradeable capacity market.

The capacity market will do a couple of things -- a tradeable capacity market. It will help the utilities avoid potential stranded costs. If they go sign a new generator up for a long-term contract, and their load changes dramatically over a period of time, there potentially would be a market they could offload some of that capacity into. It also helps the retail ESPs who cannot go out and sign up for long-term deals, that they can go out and perhaps participate in this market by shorter term capacity to meet their reserve resource adequacy requirements. So we think this is a solution out there that people are starting to get behind.

The SVMG, Silicon Valley Manufacturing Group, has pulled together a group of customers, generators, ESPs. We now have CLICA coming into this discussion and CFTA, the two large other user groups are starting to participate. And it's still a work in progress, but at least there's some -- there's a framework there that I think we can get to.

The goal of capacity market is to always have enough supply to meet the forecasted demand on a one-in-ten-year basis. It also supports investment for new resources and even existing resources.

PRESIDING MEMBER GEESMAN: What do you think FERC's reaction will be?

MR. BLUE: Well, we think FERC's reaction is going to be positive.

PRESIDING MEMBER GEESMAN: Now it wasn't to the ISO's proposal two years ago.

MR. BLUE: Well, we think that because of all the changed scenarios in the market we're hopeful. I can't speak for FERC; I don't know.

This is my last slide and we'll get moving here. Deliverability standards. One of the things that started happening is deliverability standards are now being looked at in these resource adequacy workshops. The ISO has taken the lead on putting together a straw proposal. And these are being discussed on an ongoing basis.

They're basically coming down to three types of deliverability standards. One, deliverabilaity at the interties. Two, deliverability to the aggregate of load. And three, deliverability to the load centers. It's not clear whether all --

PRESIDING MEMBER GEESMAN: What's the difference between two and three?

MR. BLUE: Two would be more like the aggregate of a utility's load.

PRESIDING MEMBER GEESMAN: So just to the service territory?

MR. BLUE: Yes. And three would get down to more specific -- just granular as you get smaller.

PRESIDING MEMBER GEESMAN: Okay.

MR. BLUE: And it's uncertain whether the -- as the last I heard of the discussions the third one was potentially even getting dropped, which we don't support. But that's -- we're working on that. It's still a work in progress, as well.

PRESIDING MEMBER GEESMAN: What would the rationale be for dropping the third one?

MR. BLUE: I haven't -- I don't know. I

haven't been participating in those discussions. It's just been reported to me. Potentially that it's just too complicated right now. They just want to start with something. The easiest one, of course, is at the interties, and then I guess you get the easy ones first and work on the other ones later.

The PUC has actually stated that deliverability standards will be incorporated into the utility's long-term resource plans, which they hope to approve by the end of this year. So, we are going to have some form of them. And we'll just have to see what comes out of the PUC process and what they end up adopting.

And with that, I'm done. Tim Hemig has to catch a plane, and I think he's got a few comments. And then we'll get right into the Q&A. And I'm going to participate in the Q&A, too. Thank you.

PRESIDING MEMBER GEESMAN: Thanks, Greg. Tim.

MR. HEMIG: Thank you. Good afternoon. The way I thought I would approach this is just have a few comments on the slides that were presented earlier. And I think they will actually address some of the environmental panel questions that were also brought up. I'm going to probably be jumping around a little bit, trying to collect my notes here.

But first on air quality, I have a couple of comments on air quality. And specifically slide 38 where we're talking about aging plant retirements and whether or not that would be a net decrease in air emissions in a particular air basin.

I wanted to present our opinion on that, and some of the -- what I believe are some of the procedures and facts in that case.

Really, first and foremost, the air emission from an aging power plant, especially the way it was pointed out, that most of these have SCRs, actually very very low. We talked about NOx emissions and PM10, PM2.5 are extremely low. And in fact, in many cases as low as even new units going in. And certainly the West Coast Power assets are equipped with SCRs.

When you talk about whether or not one of those units shuts down there's a net improvement to air quality. I'll say first if you just shut it down and not replace it, obviously there's no emissions from that unit now. And if those, some of the things described here, if another unit in the area takes on that load and maybe you might have emissions from that unit now.

But the way it works when you try and bank emission credits, when you shut down a unit, there are significant discounts that you take when you bank those emissions. I mean up to 90 percent, you assume, first of all, how much you've ran. And if you haven't run a lot of operating days you get discounted. You get discounted for best available control technology.

So when you shut something down and then those emissions and banked emissions go towards a new unit, whether it be power or another combustion source, you have significant net improvements to air quality because you have far less emission credits.

Then when the new unit comes online it has best available control technology. And when it uses those emission credits it has a 20 to 50 percent additional offsets it has to supply to come online. And when a new unit comes online it has to bank its maximum emissions, its worst case permitted emissions under its worst case operating levels. So you have a lot of conservatism in there. You have a lot of offsetting, ratioing that have a net improvement to air quality.

And what I'm trying to say is that when you relay that into a replacement of an aging power plant with a new unit like Greg was talking about, you do see significant net benefits to air quality in that case. And even moreso because you're going to put on a -- most likely a combined cycle unit that also has less emissions on a per-megawatt hour basis.

So you have significant benefits to air quality. You get really the same emission level out of the stack, but you get more megawatts from that emission source. So, I just wanted to point out I think there's some benefits that we may have not included that we should include in this study.

Secondly, on the air quality discussion point, we're talking about emission reduction credits in South Coast, and the reclaim program. That is just a NOx program only. So some of the issues about whether or not a particular generating unit has incentive to shut down rather than mothball and kind of delay its decision point, in South Coast that is not necessarily different situation because of reclaim.

The reclaim credits and the NOx part of it you do get to retain those credits. But the particulate matter and the carbon monoxide and those, the other criteria pollutants, is the same program. So the ERC -- the question about whether or not you're banking, your ability to bank significant credits that could be used for redevelopment, that does affect the retirement decision in the South Coast air basin. So I wanted to point that out.

A couple comments on cooling water. And I think maybe the best way to handle this is to kind of jump right into what I believe is the new regulation and how that, the timelines and the requirements of the new regulations, some of the points brought up are that there's a lot of uncertainty with the regulation. And I believe that the phase two regulation provides a lot of certainty. And the uncertainty parts of that don't necessarily mean that we don't think anything's going to happen, it's just whether or not the range of the controls which would be required then.

So really, in fact if I understand it,

this week is when they're supposed to put this regulation in the Federal Register. So any day it's going in the Federal Register. That's the trigger point for when an existing intake structure that has more than 50 million gallons per day has to start its compliance activities.

The first thing you have to do is you have to lay out a schedule. You have to work with your particular director, which is the Regional Water Boards in this case, to develop a schedule for where you will submit a number of compliance requirements for your intake structure.

The regulation is really, is probably going to be about the same timeline for all facilities because if your permit expires within four years of the Federal Register date you're really all under the same schedule. And all permits expire in five years. So really, when you look at it, most facilities would be under a very similar schedule to what I'm going to lay out here.

So the first thing you do is you request a schedule for submittal. And you have three and a half years from the Federal Register date to submit all of your materials. And that includes entrainment and impingement studies; your technology that you're going to install; engineering; the effectiveness of that; and all the materials have to go in within three and a half years of probably this week. So there is a pretty clear set of requirements.

And you also have, somewhere in the middle you have a requirement to submit a protocol for how you're going to collect the data. So that's really what you have to do. And there is a firm timeline on that. So, there isn't uncertainty with the schedule. I think it's pretty firm.

PRESIDING MEMBER GEESMAN: The schedule's firm, but depending on when a plant's existing NPDES permit expires, it would determine, if you will, which class a particular plant is in.

MR. HEMIG: Yeah, but if you're within, if you expire within four years of this Federal Register date you're in the same schedule. Then you have up to three and a half years to submit everything.

PRESIDING MEMBER GEESMAN: Oh, okay.

MR. HEMIG: So, most people, even if you're four and a half years, you're not in that group but you're in the same -- now you have to submit it within 180 days before your expiration. So you're really back in the same schedule.

PRESIDING MEMBER GEESMAN: So, if I tell you that our study period, for purposes of this particular report, effectively ends with the summer of 2008, I think you've just told me that these new rules will not have a direct physical impact on any plant within that timeframe.

MR. HEMIG: Yeah, and what I'm saying is you have to request a schedule from the Water Board, and then you have up to three and a half years.

PRESIDING MEMBER GEESMAN: Okay.

MR. HEMIG: So it depends on how they allow that.

PRESIDING MEMBER GEESMAN: Okay.

MR. HEMIG: And I think what I'm also saying is that knowing that that's the end point, I believe all the generators I know of, the merchants and utility generation that have intake structures are starting their activities now, because that is not a long period of time to do, you know, -- the entrainment and impingement study takes a couple years.

So I believe the activities will be started or have already started. And that really the end point is probably more like 2008 where you're going to actually have a compliance plan submitted. And that's under the longest term allowed by the phase two regulation.

MS. ALLEN: So, Tim, you envision that you may have some new entrainment and impingement data and other sampling results as early as next summer?

MR. HEMIG: I think most likely you're going to see studies starting in 2005 and maybe ending in 2006 for most facilities. I'm speaking generally at this point. Some might be earlier. If your permit expires earlier you might actually have more -- the Water Board could put more stringent requirements on you on your timeline. But I believe to make this three-and-a-half-year period there's a lot of activities that are going to start very very soon.

MS. ALLEN: Sounds like you've already started thinking about what needs to be done and --

MR. HEMIG: Yeah.

MS. ALLEN: -- who would be involved.

MR. HEMIG: Yeah, we're all struggling with understanding this 486-page regulation, but I think it's really, you get down to the meat of it, it's pretty firm on what you need to do. And there's minimum standards.

And you have to generate a lot of data to determine what you're going to do. And I think that's why if you ask the question, is any of these requirements and the cost of these requirements are going to shut a particular aging unit down, the answer is usually we don't know because you have to collect a lot of information first before you know what the cost is.

And EPA, getting to cost, EPA estimated its cost for each facility, of the 550 facilities that are regulated by this, they estimated those. But they based it on real general, nationwide information. And our facilities range from three- to about nine-million in capital costs alone. As well as, you know, the study costs are not included in that. So capital costs are somewhere between three- and nine-million depending on a facility.

And that is something that I would think is a significant capital cost that would be looked at as part of how you're going to recoup that. And when we talk about RMR, earlier we discussed RMR contracts. It was maybe being if you have an RMR maybe you shouldn't be in the study, or be looked at differently because you don't have -- you're able to recoup your costs.

Well, that's a one-year arrangement. And we're looking at something that's probably three to five and beyond. Instead of requirements and cost, that makes it difficult for a generator to know whether or not it's going to have that contract next year and keep being able to fund these studies and this compliance requirement.

So I at least wanted to bring up that. Also bring up the part about whether or not these will be challenged legally. I'm not a lawyer so I can't necessarily say I have anything more than my opinion on this. But what I understand is, well, first of all there isn't a lawsuit; there is a regulation. So, the lawsuit and what it might mean and might do, I think should be looked at in a lesser way than the known regulation. The regulation is -- and it does apply to these aging power plants.

Also, if you look at what they did in

the phase one regulation, what the legal challenge was, it was just in habitat restoration. It wasn't about all the other things in the regulation. So, I don't believe we have much uncertainty about whether or not power plants will be complying with this regulation. We do have some uncertainty about whether or not the habitat restoration compliance path might be available.

And also, again not being an attorney, but understanding that there's also other means of which habitat restoration could be used under the -- even if it is successfully challenged. There's variances and other ways that facilities still can use habitat restoration.

But what it tells everybody is that you need to look at intake controls as your first and foremost way you're going to try and comply. And those tend to be also the most expensive and the most uncertain of how effective they are.

So I just wanted to point out that when we talk about whether or not these are likely to -- the regulations are likely to be changed significantly, I don't think we can assume that at this point. It's just that we know there's going to be a legal challenge.

PRESIDING MEMBER GEESMAN: And, again, if I understand what you've said correctly, if I'm looking at a period of time between now and through the end of the summer 2008, these regs and the status of any particular lawsuit are very unlikely to affect the operation of the existing plants?

MR. HEMIG: Yeah, I think, again, only if a water board orders a much more stringent timeframe. So that's the way I understand how each of the pieces are required to be put together. And most likely between 2006 and 2008, somewhere in that timeframe you'll see facilities submitting information.

And whether or not, and that's basically your compliance plan that they approve, and then this is what we're -- particular intake has to do to conform to the new standards.

PRESIDING MEMBER GEESMAN: And your plants in California fall under two Regional Water Quality Control Boards?

MR. HEMIG: Yes, that's correct.

PRESIDING MEMBER GEESMAN: Okay.

MR. HEMIG: And then the other part about if the costs of compliance significantly, which is the word EPA used, significantly exceed the benefits or EPA's cost, I've heard several times the statement that that means you don't have to do anything. That's not the way it works. If it's significantly or wholly disproportionate then you can qualify for less of a standard to a level which is not significantly higher.

So, I don't believe there's a way that you're going to say I don't have to do anything. There is a way you're going to say that maybe saving two fish at a cost of $10 million isn't the right thing to do. So --

PRESIDING MEMBER GEESMAN: Those sound like the kind of words that end up being decided by courts, though.

MR. HEMIG: Yeah, and the significantly greater than is not defined. But one thing to point out when we talk about benefits, and one of the things brought up in slide 48 is about the commercial benefits, that EPA's estimates that they put together for the national regulation were that the commercial benefits were on the order of a couple million dollars, where the cost of compliance, this is annualized cost, were, I think, about 400 million.

And so you're looking at significantly less than 1 percent of the cost of compliance is the commercial benefits. So I don't necessarily think that when we say the commercial fishing opportunity for benefit, I'm not sure that that's something supported by EPA's own estimates and their own numbers.

PRESIDING MEMBER GEESMAN: And those numbers that you used were nationwide numbers?

MR. HEMIG: Yes, that's correct.

PRESIDING MEMBER GEESMAN: Okay.

MR. TRASK: Tim, can I ask you a question here. I know that at least one time in the past that the way that EPA and the Regional Boards would value the benefit of any changes to intake structure was based on the value of commercial fish.

MR. HEMIG: Yeah, and that's my point is that they did really in three categories. One was commercial, one was recreational and then a third was what they're calling nonuse benefits. And the commercial was the lowest of the three. Recreational benefits were higher, but also significantly lower than the cost of compliance.

And then the third is nonuse or

nonmonetized benefits and that's a tough one. Is what is the value of a fish to a person. And that's the one they didn't monetize. They did not choose to monetize that, and they left that open.

So when you talk about whether or not the cost is significantly greater than the benefits you're required to look at nonuse benefits, but not monetized benefits. So it's really, the way I look at it it's really difficult to figure that part out.

But the commercial costs, the commercial benefits were extremely low compared to the cost of compliance, and that's EPA's own numbers.

MR. TRASK: Right, I think -- well, one of the comments we received, for instance, from some of the fish and wildlife agencies was that it's true that very few, if any, commercial fish are being directly damaged by once-through cooling, but they're saying that as an overall health to the ecosystem, which would indirectly affect the commercial fishery.

MR. HEMIG: And then probably the last thing -- sorry to take up so much time --

PRESIDING MEMBER GEESMAN: Not a problem at all.

MR. HEMIG: -- is really what, you know, the value of the existing studies at facilities have undertaken, and in many cases there's the original studies back in the '80s. And from what many facilities, and I'm not sure I agree with the statement about many facilities did not do any study. Only speaking for ours, but I think most facilities have. We're required to do some kind of a study. Most of them did something originally, then did updates in the late '90s.

And the value of what those studies bring to us is actually still very helpful and extremely valuable in looking at the effects of these intake structures. I don't think we should discount these studies out of hand because of the age. Because in many cases they were updated as recently as, you know, five to seven years ago.

So, whether or not you spend a lot more time studying rather than getting into implementation really is based on whether or not these older studies still have value. And you can study this another two or three years.

The way we looked at these things and did a lot of surrogate studies in the Santa Monica Bay and showed that these older studies are still very good descriptive of the current conditions. And that getting faster into implementation would be a better thing than ongoing studies. And that the margin of conservatism in these old studies and the updates in studies show that even if you're off significantly, the impacts are so low that to the adult populations of fish, that you are not going to show, even with a new study, anything different than insignificant levels of impacts.

So I think we should not discount out of hand and say anything about the old studies generally that they're not applicable still.

PRESIDING MEMBER GEESMAN: Without commenting on the old studies you don't envision the Regional Water Quality Control Boards affecting any of your plants in California ordering you to early implementation of the new regs before the summer of 2008, do you?

MR. HEMIG: I'm actually bringing this up because I have been told that some of those regional boards may want to get more swiftly into implementation rather than studies.

PRESIDING MEMBER GEESMAN: And that could happen then before the summer of 2008?

MR. HEMIG: I believe it's possible.

PRESIDING MEMBER GEESMAN: But if you did not agree with the recommended implementation, presumably on your company's initiative you could suggest additional study? I'm trying to figure out what --

MR. HEMIG: I see where you're going. And I think the better way to answer that is that the decisionmaking about -- actually the very expensive study would commence next year, maybe even this year in some cases. The decisions when to, you know, what's the word, it's actually a fishing -- fish or cut bait in this case is that you're starting getting into significant money early, before 2008. And you're planning and you're making decisions early.

And I think those decisions will affect retirement, will affect other investments at a facility earlier than 2008, even though you may not be getting into an implementation phase.

So I think that's the way I would rather answer that, but there's a lot of flexibility in a water board's decision to take the old studies and say they're still adequate, and moving into implementation earlier, they can do that.

It's very clear in the regulation that existing information is something you can use in your demonstration. And it's fairly flexible.

So, you're trying to nail down when the money will -- the big money might be required. I think that is longer term, but some of the study costs are significant enough that would affect how a facility, its retirement decision earlier.

PRESIDING MEMBER GEESMAN: Okay.

COMMISSIONER BOYD: Tim, have any of the companies who may be drawing water from a common area, i.e., you mentioned Santa Monica Bay, considered if there's any feasibility to come together to pay for the cost of some of the studies that would be generic to all?

MR. HEMIG: Yeah, absolutely. There's been discussions, and there's actually been a good history of that. In particular, El Segundo and Scattergood have had about 25 years of monitoring data, impingement monitoring data that's been going on. And collectively shared and studied in one report, because of the proximity of those two facilities.

And the 316(b) studies originally were done in the same manner for Southern California

Edison. And it makes a whole lot of sense to continue to do that. And I have been talking with other parties about that, to do that again.

DR. TOOKER: Tim, I have a question. If you make decisions, if your company makes decisions to go forward and make investments for planning and assessment, and at some point were to decide to close down a facility, would the results of those studies be applicable to a new plant at that site?

MR. HEMIG: Yeah, they should be. An entrainment study to me is there's not a lot of different ways you can do it. There are a few, but you can collect data that should be able to cover all the different ways that should satisfy anybody that's interested in that information for redevelopment or for existing facilities. I believe that a study should be able to cover both.

And, in fact, it's also potentially valuable to a desalination project. So there's some value in that kind of a project. And that kind of decisionmaking might affect the desalination project, too. So when we're talking about what's the effect of existing -- an aging power plant and the effect of these compliance costs, it's the same thing for a desalination plant. Because they may be required to participate in some of those retrofits to keep that cooling system going.

So, for example, the Poseidon project and the City of Carlsbad. The City of Carlsbad started; they did the notice of preparation for CEQA, they started that last month, maybe this month. And so their CEQA process has been initiated. And obviously the Encina Power Station's ability to maintain that intake structure affects their project. So there's a lot of things going on, and desalination is definitely one of the projects that could be affected.

MR. TRASK: Tim, in our consultations with the resource agencies covering the coast, we've gotten some comments that the past studies are legitimate, and others that are not. And that the gist of it generally is around the sampling techniques used, where the samples were taken and how the samples were taken. Can you comment on that?

MR. HEMIG: Actually on the plane on the way here I was reading my study plan for one of my facilities, and kind of find it hard to believe that there's a lot of question about how you collect the sample. I mean you throw a net in the water and you tow it. And you know how much water went through the net, and you know how many planktonic organisms you collect. And you count them and now you have the number of organisms per cubic foot of water, for example.

I don't really find that -- and I'm not a marine biologist, so I need to kind of step back on that. But I don't believe there's a lot to debate about how this information is collected. The point of where you collect it might matter, but it's also, remember it's a one point in time set of data. You collect this in one year and, you know, several points of time during that year, probably monthly or maybe biweekly. And now you have data that represents one year. And things change so much that we just need to recognize that there's a lot of uncertainty and limitations in any of this data.

But, I don't think there's, in my mind, a lot of significant issues that would affect how the study plan is put together. And it should be something that the water boards actually being very experienced with right now. They're doing a lot of studies, and I think they're getting a little bit better at what they believe is an adequate study.

MR. TRASK: Thanks.

PRESIDING MEMBER GEESMAN: Thank you, Tim. I appreciate your participation.

MR. HEMIG: Okay, yeah. I apologize for running out.

PRESIDING MEMBER GEESMAN: Perfectly understandable.

MR. HEMIG: Make sure I make the plane. Thank you.

MR. TRASK: Thank you. Is there anybody else in the audience who would like to comment on environmental issues?

Okay, I think it's probably best that we shift into our other panels. Any interest in going through the questions for panel number one, concerning the proposed study list and the role the aging plants play?

PRESIDING MEMBER GEESMAN: Well, I want to come back to the preference that Greg recommended the state reflect for redeveloped projects. And ask you again, how would you see that preference manifesting itself? What would you have the state do to show such a preference?

MR. BLUE: First we need somebody to actually say it. And that hasn't happened yet.

PRESIDING MEMBER GEESMAN: Well, I think I --

MR. BLUE: I think you can show that in a couple --

PRESIDING MEMBER GEESMAN: -- I can go back decades and show you --

MR. BLUE: -- of ways.

PRESIDING MEMBER GEESMAN: -- statements of preference in Energy Commission --

MR. BLUE: Yeah, I --

PRESIDING MEMBER GEESMAN: -- reports for it and --

MR. BLUE: Okay, I would say it could be reflected when the utilities file -- well, it could be reflected through deliverability standards. It could be reflected in utilities' long-term resource plans that do get approved by the PUC. They can come back and impose -- PUC can take the plans and they can come back with some orders, you know, reflecting that. And the PUC has even made that in their January 22nd procurement order. They stated a preference for the brownfield plants, that's the term they used.

In fact, it says that the utilities should look at brownfield first before they look at anything else. Statements like that, and the way they get enforced would be, and manifest, as you say, would be through, in my opinion, through the Public Utilities Commission on how they approve the utilities' procurement plans.

PRESIDING MEMBER GEESMAN: Okay.

MR. BLUE: I'll let other people who want to answer that, as well.

MR. PIGOTT: Sure, I'd like to talk about that same issue because I think we're diametrically opposed. With Calpine we don't have any aging power plants, at least that are fossil fuel fired. And one issue that we feel very strongly about is that there should not be any preference for repowered plants.

We have developed facilities at what you would call brownfield sites. For example, Los Medanos or the Delta project. They're both within visual range of the Pittsburg Power Plant. Our facilities were developed and built as merchant plants. At the same time the Pittsburg plant, the owner of the Pittsburg plant could have repowered if they had decided to. Maybe if they had had a preference they would have and we wouldn't have. It really makes no sense to give a preference.

And particularly when you look at where some of the locations are of the existing plants. I don't think anyone today would propose building a power plant at the beach. And I think that there are a lot of other sites that are perfectly acceptable to the public. And it should just be a wide-open competition for where those plants are sited. It shouldn't be a siting preference or a power procurement preference, from our point of view.

PRESIDING MEMBER GEESMAN: Greg.

MR. BLUE: Just a quick response. I think we have, as I stated that was in our last presentation, and we've had some dialogue with the Legislature who told us in no uncertain words that they don't like preferences in the Capitol.

And so while we --

PRESIDING MEMBER GEESMAN: Maybe they just don't like preferences for you.

MR. BLUE: No, no, it's for anybody, for anybody. It's a policy they don't like to have preferences. So, that was our initial position.

There is another way to manifest, which I think Calpine would agree. It talks about competition. And I think what you do is if you set up the solicitation, competitive solicitation, where you value the winner based on the lowest cost delivered to load. That's the cost to build the new plant, the cost for transmission upgrades, the cost to use the transmission network system, the cost for transmission losses versus a plant which is located in the load center.

There could be competition that would work very well. The consumers in California would benefit because all those other costs are rolled into their bill. It may not say generation, but they're rolled into their cost. So, you know, that's another way to manifest it, if you set up a solicitation that's based on lowest cost delivered to the load center.

PRESIDING MEMBER GEESMAN: Yeah, I guess the one hesitancy that I have there would be attributing too much precision to those costs of delivery and spending too much time striving for too much precision. I think just given the reality of the way regulatory processes work, particularly in the circumstance such as I think we confront now, time is of the essence.

And the state's various adventures in the past in resource planning conjure up the BRPU whenever you get two or three resource planners in the same room. Greg, --

MR. McCLARY: Commissioner, I might offer as well, I think that in a certain respect what Greg's asking for is a goal of this study, in fact, to the extent that this study identifies and spells out some of the policy backdrop and criteria that goes into the siting process.

Any of these kinds of projects that come to you as for siting, not all might, but you know, presumably many would, of these kinds of redeveloped or repowered projects, presumably that would also -- the value or otherwise of keeping aging plants or plant sites in operation should be part of the backdrop that you would be incorporating because of this study, because of this process.

PRESIDING MEMBER GEESMAN: Perhaps. I have a very limited experience with our siting process. I've been, at least in the cases that have come before the Commission while I've been here, which is almost two years now, I've been surprised at how many acceptable sites there are. Although I doubt any of the applicants would join in this, but how easy it is to find such sites.

I'm told by Commissioner Boyd that once we get down to San Francisco our experience is likely to be a little different, --

(Laughter.)

PRESIDING MEMBER GEESMAN: -- but I don't know how you would actually attach a meaningful distinction. I think that we can certainly associate a rhetorical distinction with it. But as I said to Greg, I can go back more than two decades and point to Energy Commission reports expressing a preference for what I think we've consistently called repowerings. But what I think are the same thing as what you call redevelopments.

MR. McCLARY: I hear you.

DR. TOOKER: Greg, I have a followup question. Why is it that the characteristics you're talking about of existing sites wouldn't be reflected in the ability of a generator to offer power at competitive prices in terms of access to transmission and load centers, et cetera?

MR. BLUE: You say why wouldn't it be?

DR. TOOKER: Yeah, why do we need a preference when you have strategically --

MR. BLUE: Yeah, as I stated earlier, that was what I presented a month or so ago. It's not necessarily -- I would still like to see it, but I also am pretty pragmatic, and don't think that that's actually going to occur.

So, therefore, you get into issues like what I think is going to result -- we can get to the same result from my point of view, strong deliverability standards is going to be there. Which gets back to the issues of we already are connected to the load. I mean, yes, it will all -- we're not pushing that issue as much as we were.

PRESIDING MEMBER GEESMAN: And I take it, though, that when you say strong deliverability standards, you would actually prefer to see that to the load center --

MR. BLUE: Correct.

PRESIDING MEMBER GEESMAN: -- as opposed to the aggregated load or to the intertie?

MR. BLUE: That's correct from our point of view, yes.

PRESIDING MEMBER GEESMAN: Yeah.

MR. TRASK: Joining us is Audra Hartman from Duke Energy.

MS. HARTMAN: I would just kind of build on Greg's comments about redevelopment, repowering. We are looking at several areas, and you're all familiar with our Moss Landing facility that we built new generation -- we're looking at doing that at several of our other sites around the state.

And looking for encouragement, incentives to continue that process. We're looking at our South Bay Power Plant, building a new facility down there to replace the existing one. Other sites that are out there. And looking to try to build a partnership with the community down there and with the utilities.

And I don't think we would have a problem competing in some of these competitive processes if all of the costs for a new facility are included, and we are able to compete on the table --

PRESIDING MEMBER GEESMAN: Right.

MS. HARTMAN: -- with all of the costs. I think we would do very well. But I don't actually think that that's the case right now.

PRESIDING MEMBER GEESMAN: This is the long hope for competitive, transparent procurement process. Or I guess sometimes they say transparent competitive procurement process.

MR. BLUE: Undefined, so far, by the way.

PRESIDING MEMBER GEESMAN: Yeah.

MR. BLUE: Yeah, we're working on that.

PRESIDING MEMBER GEESMAN: You know, I guess I'd pose the same thing that I did to Greg. I can tell you, speaking solely for myself, but even assume that all four of my colleagues agree, we'd like to encourage you in each of those projects. I'm not certain what that actually means in terms of conferring any benefit on you. Certainly I don't see it as a preference.

If a project comes to us that meets all of the different environmental and safety standards that we apply in our siting process, we're going to issue a license. And, as you know, we seem to issue a very much larger number of approvals than we do disapprovals.

But, you know, that encouragement, I think, is probably worth a ticket on the San Francisco Railroad minus $1.

MS. HARTMAN: I know there's several proposals out there to try to reinstate an expedited siting process for repowers. I would just say, as we go along, in the process maybe look at some of the pros and cons, things that we've done in the past that may be improved.

I don't have it before me today, but I know that we have a list of things that we've loved about the Energy Commission and the process and things that we haven't. And we'd love to come talk to you about --

PRESIDING MEMBER GEESMAN: I won't ask you which list is longer.

(Laughter.)

PRESIDING MEMBER GEESMAN: I hear what you're saying. I guess I don't want to get too far down this particular tangent, but one of the concerns about any of the various expedited siting proposals is it's real easy to get the appointed officials or elected officials to say, yeah, that sounds like a great idea, where do I sign.

But then when you actually try to apply it, the staff or the various legal authorities that have to apply a specific standard say, you know, we just don't have enough data from this applicant to start the clock yet. So the expedited calendar proves to be more of an illusion than anything else.

DR. TOOKER: I'd like to say something here. Don't you think it's true that there's more than one side to this coin? We've talked already today about water issues, once-through cooling and changing regulatory paradigms.

So the existing infrastructures and sites have some benefits, some advantages. But they also have some liabilities that I'm sure you must be considering in terms of your long-term plans.

PRESIDING MEMBER GEESMAN: What would you see as liabilities?

DR. TOOKER: Well, I mean we were talking about EPA's new rules.

PRESIDING MEMBER GEESMAN: But they're going to apply to new facilities, as well.

DR. TOOKER: Right.

MS. HARTMAN: The only comment I would make, because it depends on which facility you're looking at, and what cooling method they're using. I think that's where you're going --

DR. TOOKER: Right.

MS. HARTMAN: -- with your question? Is that in the future, for our future projects we're looking at different options and trying to get community support and buy-in before we come into the process.

So hopefully that will try to address some of the concerns with it.

DR. TOOKER: I think that would be great.

MS. HARTMAN: That's been our goal, I think, all along with some of the other facilities we've had. We just have varying degrees of success.

PRESIDING MEMBER GEESMAN: Before we move on I did want to come back to one of the things you said, Greg. I think you were calling into some doubt one of the staff assumptions about when locational marginal pricing would come about. I think our staff presentation suggested that it was something that could go into effect in '05. You said several years off.

MR. BLUE: I believe it's going to be several years off. I believe they're going to have to get MDO2 done -- well, I don't know what they're going to call it now, MDO8 maybe, -- done first before they get to location. That's like the step first.

I have not seen any indications. There are nobody, no study groups, no work groups, anybody talking about LMP to date. We're dealing with these other nearer term issues. That's a longer term issue from our point of view.

MR. TRASK: We also have Scott Peterson from SDG&E who'd like to make a comment.

PRESIDING MEMBER GEESMAN: Hi, Scott.

MR. PETERSON: I just wanted -- I'm the Director of Grid Operations for San Diego Gas and Electric. My interest here is though I am the prior manager of South Bay Power Plant, when it was run by San Diego Gas and Electric, so I think I am one of those aging power plant operators here.

(Laughter.)

MR. PETERSON: I just wanted to make some comments, you know, obviously we're trying to --

DR. TOOKER: Grammatically, does aging apply to the power plant or --

(Laughter.)

MR. PETERSON: Excuse me? I think the

plant's probably aging better than I am.

You know, as we think about all of the things we're trying to accomplish, we're obviously trying to balance everybody's needs and desires and wants and aspirations here. You know, my company obviously is in one of those load pockets we talk about where there's limited transmission, there's limited inservice generation. A lot of generation outside connected to interties within inabilities to get generation into those. We site facilities perhaps in not the most opportunistic areas that we could to try and get transmission built.

From the standpoint of talking about preference for power plants, you know, San Diego Gas and Electric is not a real strong proponent of providing preferences. What we're really looking at is the economics of the projects and where they make the most sense. Yeah, when I was at South Bay we would have loved to have repowered South Bay Power Plant, but my general impression is you'll probably never get that to happen on the Bay anyway. So you'll go dry cooling anyway and similar type of things.

A comment was made about building these

power plants on the ocean view property which is great places to be. So I just encourage us not to go too far down the road in trying to expedite repowers because they should be the way to go. I think we need to look at the economics. If there's a desire to have power plants, and it needs to be an expeditious method for that to happen. If we repower South Bay we're not going to repower South Bay, we're going to put a new plant there, just like you're going to put a new plant somewhere else.

So, just look at the total economics for the group as a service territory. And we'll try not to have any more transmission emergencies hopefully this summer.

PRESIDING MEMBER GEESMAN: Well, but let me explore that a bit because I'm one of those that thinks that the state has done a pretty large disservice to your ratepayers in terms of the transmission decisions that have been made affecting your service territory.

But recognizing a certain pattern seems to be developing in terms of addressing the transmission needs of your part of the state, should, in fact, we look at power plants inside the load pocket, if you will, as entitled to some form of preference compared to power plants that are more remote and would require certain leaps of faith about our willingness to site transmission into the San Diego area.

MR. PETERSON: Well, I think it's never an all-or-nothing type of answer in those type of things. I think obviously there are two projects that are underway right now, with the Palomar project and with the Otay Mesa project. Obviously we're seeking approval for those, but there's still thorns in some of those. In the Otay project, as far as having adequate transmission for that.

I think it's a combination of inservice generation, but also opening up the transmission market so that you can have competition. You know, if we just create everything inside the service territory and it's just enough to get by, you have no ability for competition to come in.

So, it's kind of a mixture of all of those things. And we obviously recognize that we need new generation in our service territory. We just don't want to get so locked into it we make a special preference because it's an existing power plant site, which will really just be like a new site, anyway, because you're just going to put a whole new combined cycle. You're not going to use Bay water cooling; you're not going to use ocean water cooling. It's just you happen to have a piece of property.

PRESIDING MEMBER GEESMAN: Yeah, I appreciate what you're saying. And I actually think your rates today are higher than they would have been by some measure if the state had been a little more attuned to better interconnecting you with the rest of the west.

MR. PETERSON: Well, being the operator of the grid, it becomes very dicey some days when you have two interties. You wanted a third, but you were told you didn't need it. Yet you find yourself in transmission emergencies and other things.

PRESIDING MEMBER GEESMAN: Well, you were told you didn't need it, as I recall, within the five-year window, --

MR. PETERSON: Because we needed it in six years, I think.

PRESIDING MEMBER GEESMAN: -- two or three years of which had already passed.

MR. PETERSON: Right, that's correct.

PRESIDING MEMBER GEESMAN: Yeah. Go figure. Greg.

MR. BLUE: A final word on preference.

(Laughter.)

MR. BLUE: I agree with the San Diego Gas and --

MR. PETERSON: I'm a power plant operator, by the way, so I like power plants. So I'm not --

MR. BLUE: Yeah. I think the issue of the transmission is very important, if you're talking about the economics of the long-term viability of existing generation. Because if and when the new generation does come online in the San Diego area, I would love to have a place to sell my power out of that area. And right now we're constrained --

PRESIDING MEMBER GEESMAN: Right.

MR. BLUE: -- to 500 megawatts, I believe, is the export capabilities at times.

I think one other thing we shouldn't forget is we shouldn't forget what the ISO will have to say. There are some plants that they've determined are quote, "super critical" to the grid. And we should at least, you know, hear from the ISO on this topic.

MR. PETERSON: Yeah, talk about critical plants. I'm more concerned about the plants that don't have RMR versus the ones that do have RMR. I mean the RMRs you still have a backstop; I mean I've been around long enough to actually have been involved in helping to create the RMR contracts, which I kind of wonder why we did at the time.

But, there are backstops in the RMR. We talk about, you know, investing capital; you may not get it back. But there are conditions, too, there's always failsafes. At the end of the day if you say I can't -- the ISO doesn't need any more and I can't make it work, you get your money back.

But the plants that have nothing and are truly working on the margin, those are the ones that worry me the most, because those are the ones that could very easily give their notice and be gone very shortly.

MR. BLUE: And then those are the ones that are located in the L.A. basin for the most part.

MR. PETERSON: Yeah, San Diego's --

PRESIDING MEMBER GEESMAN: Those are the condition one plants?

MR. PETERSON: The condition one plant is the one where they play in the market. Condition two is when they go fully just to be there for the service of the ISO.

PRESIDING MEMBER GEESMAN: Okay.

MR. PETERSON: And all of, you know, Duke, I believe is on condition two; and Encina, I think, is condition one, still?

MR. BLUE: Currently.

MR. PETERSON: All right.

PRESIDING MEMBER GEESMAN: Okay.

MR. TRASK: Thank you, Scott.

MR. MILLER: Hello, I'm Tom Miller from PG&E. And I just want to take the discussion a step further. Yesterday I attended the Market Surveillance Committee meeting where they talked about the new transmission economic assessment methodology.

And so given the context here that's been spoken to, this aging power plant study that the CEC has done a very good job on so far, really highlights a lot of the issues going forward. And I think what we encouraged at the meeting yesterday was that it would be ideal to incorporate a process of transmission economic evaluation into the IEPR process.

Because, as we know, you know, generation and transmission solutions and other resource choices can be alternatives to each other. So I think it's very important to have a process ideally that can bring the choices together. So, I --

PRESIDING MEMBER GEESMAN: That's a very good point. And it's our full intent to do that. I think it's something that needs to happen.

MR. TRASK: Any further comments? Do we want to try to answer the questions under our discussion panels here?

PRESIDING MEMBER GEESMAN: Sure.

MR. TRASK: Well, I guess we can just start at the top. Should any individual unit at any plant be added or removed from the APPS study list? And if so, why?

It's deafening.

MR. BLUE: I think the list is adequate from our point of view. I think you're going to get all the information you need regarding existing or aging power plants from your study group.

I think all the issues you're going to see are probably located within that study.

MR. TRASK: Are there any other important aspects to consider concerning the role that aging boiler units play in the integrated electric and natural gas industries?

Do the issues of concern for aging boiler plants apply to other categories of generators, such as peakers, nuclear plants or hydroelectric plants?

MR. BLUE: Well, actually one of the issues that we have, but I don't know that it falls within the timeframe of the study. That's the part, we're looking at a limited timeframe. But we think that there's going to be an issue with the nuclear plants, particularly with both PG&E and Edison, and not San Diego, applying to have their steam generating units replaced at their nuclear facilities. And the relicensing that's going to come up.

To me that's an aging power plant. Just like we are. And so, unfortunately I think the study is so far along I don't think you're really going to be able to accomplish that, much more than a passing comment about it.

PRESIDING MEMBER GEESMAN: Yeah, I think we tee that up for the '05 study. We've largely defined that as not likely to be a problem before the summer of 2008.

MR. BLUE: But I'm just saying it's out there.

PRESIDING MEMBER GEESMAN: Yeah, no, you're absolutely right about that.

MR. BLUE: Okay.

MR. TRASK: Our analysis does assume a 20 percent probability that one of those two plants would not be available in our timeframe due to early problems with the steam generator tubes.

MR. PIGOTT: I have a comment to this question. In reality the issues, or at least the solutions that would apply to aging power plants really apply to any high heat rate fossil fuel unit in the state that doesn't have a power contract.

If we looked at peakers, Calpine's situation we have a unit that used to be a qualifying facility that is no more. And I think we're in a similar situation to a lot of the aging power plants in that the lack of a capacity market, the capping of electricity prices during peak hours, and the must-offer obligation that's imposed on merchant generation that discourages utilities from signing long-term contract, all of those things affect any high heat rate unit. It doesn't have to be an old one.

PRESIDING MEMBER GEESMAN: You're right. We need to bound our study somehow. We're responding to, I think, several years of rhetoric across the street about the aging power plants and the plants that were older than the guy that signed the DWR contracts.

I'm curious. Both you and Greg have raised this issue of abuse of the must-offer provision. That issue has been pretty clearly in front of FERC for awhile. Your industry has not been at all shy or inarticulate about laying out your arguments. But, at least from my perception, you've gotten no traction at FERC. Do you expect that to change? Why hasn't the argument been successful in Washington?

MR. BLUE: I'll give you my opinion.

MR. PIGOTT: Well -- all right, why don't you go first.

MR. BLUE: My opinion is that it was put

in place at the time of the energy crisis to answer criticisms of alleged withholding of power by the power plants.

I think that, with a couple of things that have happened, that one, the markets have stabilized in California. That was the reason why it got traction then. And all the arguments that were made back then.

I think that there is a high likelihood that some action will be taken on this before the end of this study for sure, by FERC, removing this.

I think with the orders last week, I guess it was last week, on the generator maintenance standards, that were a result of SB-39XX, which allows the PUC to have a much greater role in maintenance and operations of both existing facilities and new facilities, that that will go a long way to alleviating the reason why they needed the must-offer.

So, I think circumstances are such. And we are, you know, there has been discussion within our industry of going to FERC again and asking for the removal of that. We felt, at least the discussion has been to date that politically doing that before a summer peak period is not the best time to do that kind of a thing. So, my guess is there'll be some sort of activity this fall; a re-engaging on that topic.

PRESIDING MEMBER GEESMAN: Like after November?

MR. BLUE: Yeah.

(Laughter.)

MR. BLUE: Potentially.

MR. TRASK: I don't intend to speak for the ISO, but we have heard from them that they are planning to make a filing to FERC on the must-offer. I can't characterize what that filing is, but that they hope to get some changes from that filing.

MR. BLUE: Just to respond to that, I know that FERC -- we've had a lot of dialogue with the FERC Staff -- I mean, excuse me, the ISO Staff on the must-offer. And compensation for that must-offer. And we know that the ISO is aware that if you respond to a must-offer over a period of time you do not recover your full costs, Terry Winters' aware of it; their staff is aware of it.

I'm not saying they're going to go out and file a support, but they are aware of the situation. And I believe that their tariff filing on must-offer allows the unit to participate in other markets which perhaps will help.

So I don't think that -- I think the times are different now and such that I think we might be able to see some traction on that issue.

PRESIDING MEMBER GEESMAN: Okay.

MR. PIGOTT: Yeah, I think FERC and the ISO have gone back and forth a few times on this. The last one that I'm familiar with was the either/or must-offer. Either offering the day ahead when that ultimately develops, or the real-time market.

And the ISO might have had a problem with it. And I'm not sure where it stands right now. But it is certainly an issue for us.

PRESIDING MEMBER GEESMAN: Go ahead, Matt.

MR. TRASK: Should the Committee study the reliability and environmental aspects of other generating sectors in the IEPR process?

I think we have already heard that at least the nuclear plants are likely to be a subject of the 2005 IEPR.

MR. McCLARY: And this is just an

observation that, you know, similarly to the nuclear plants, there obviously are other kinds of generators in the state. And some of them are aging. The hydro system has a lot of older plants than any of them that we're talking about here.

We may have done not a disservice, but I think that Commissioner Geesman characterized this correctly, this is the study of the plants that have been accused of being that elderly fleet of gas fired power plants, mostly owned by non-utilities that has been identified as a cause of concern. And I think appropriately so.

PRESIDING MEMBER GEESMAN: Yeah, I think actually the phrase has dirty in there, too. Dirty old power plants, or something like that.

MR. McCLARY: In public, yes.

(Laughter.)

MR. TRASK: Well, moving on to the questions under our panel two. What are the likely effects on aging plant economics and retirements of the pending decisions by the California Public Utilities Commission concerning procurement, resource adequacy and locational pricing?

I think we probably covered those fairly well. Is there any desire to add some comments there?

MR. McCLARY: Just this. I think we have heard a lot of very good comments and observations on all of these. The way the question's phrased is actually, I think, a little bit backward from the way you're taking it in the study, which I think is appropriate. Which is how do these policies and these things that are coming up, if these policies are ones that we want to follow, how does the possibility that we have some older power plants that might be retired affect our ability to follow through on the policies that we choose to pursue. Rather than make the aging power plant economics the focus, it's the aging power plant economics impact on where this Commission wants to go that should be the focus.

MR. TRASK: You're saying that the retirement of plants could have as much effect on the success of procurement as the other way around?

MR. McCLARY: Actually, yeah, in a broad sense. I think underpinning this and several of the other questions that you're addressing here is the notion that one of the things we've learned in the last few years is that a market works better when it's got a nice solid supply base behind it.

And these are part of it. And the question we're trying to answer here is how important a part, and in specific areas how does that affect it.

But there is a broader question, you know. Is the impact of potential retirement enough to cause concern about the overall supply/demand balance.

MR. TRASK: Interesting point.

MR. BLUE: I think the biggest thing in the near term that's going to have the most effect is the resource adequacy requirements. And it kind of ties in, as Steve was saying, there's a lot of things kind of tied in with that.

Because by definition, if you have a resource adequacy requirement for the utilities to meet their peak demand, and then 15 to 17 percent on the peak day, that's going to create, I think, a market to keep some of the existing generation around because you can't fill all that. I don't think you're going to fill all that need with baseload generation.

The resource adequacy, by definition, is going to cause you to have excess energy. You're going to have more energy than you need. And that's going to be the stabilizing effect on the energy prices.

However, you can have such a stabilizing effect as that you're not able to recover your full costs, which leads to why you need to do that in association with a capacity market. And the capacity market will, you know, hopefully cover your fixed cost, your return on investment, return of investment. And you can recover hopefully your variable costs out of the energy markets.

And even the ISO has stated on many occasions that one of the reasons they've been advocating the forward markets or the capacity markets or the like is that they don't expect people to recover their full costs out of their energy markets, spot markets and the likes.

So they're all kind of tied together to some degree. And that's the thing that's on the closest horizon for us. The PUC is potentially set to rule on some form of resource adequacy through -- they're going to rule on this through the utilities' long-term resource plans. That's how they're going to implement -- that's how they're going to enforce it, excuse me.

It'll be set at some point in some time. And it's probably going to be sooner than 2008. And the way they're going to enforce that is through the utilities' long-term procurement plans. That's my opinion. I believe that's the way it's lined out in the decisions.

So, that's going to have the greatest impact on us the quickest than any of the other things you've put down here.

PRESIDING MEMBER GEESMAN: But you would like to see those resource adequacy requirements met with multi-year contracts, as I understand it. What makes you think that load serving entities won't have every incentive, particularly if the energy effects are what you suggest, in simply signing one-year contracts?

MR. BLUE: Well, once again, I believe that the -- I hate to say this, but the power's at the PUC to make that happen or not make it happen. And I think what I've heard out of the PUC to date is they want to see a portfolio of short-term, intermediate and long-term. That's what they've said in many of their filings.

So I think they're looking for the

utilities to file a portfolio. And I'm assuming that utilities would want to have a portfolio. Because if you do, you don't want -- well, we went short once. You don't want to go all long. And you want to have something to roll off. You want to have something that in two or three years the prices that roll off, because if prices change, okay, you're done with that one. You can sign up again at a lower price you hope.

MR. McCLARY: I think it's an important issue, though, because I think Greg is right, that the immediate prospect for many of these plants' economics is what comes out of the resource adequacy process, and how that's defined.

But a lot of the proposals for how resource adequacy could be implemented, even the capacity market kinds of proposals, really only go forward a year. And that brings us back to the kinds of issues that have been talked about with the RMR contracts being just a year. The lack of multiyear commitments that allow plants like these to make capital commitments that take them beyond the immediate term.

Resource adequacy is the nearest source of, you know, gain or salvation for some of these plants, perhaps. But I don't know that it is actually, so far the forms that it's taken, the ultimate one that's going to address that underlying question. That still has to be looked at.

And this is maybe a bit off the topic on this question, but I do think one of the things coming out of this study that's been good to see and to build on, is the interaction with the ISO on identification of the consequences of plant retirements and the kind of work that they're doing and the reliability assessments.

And also the continued highlighting of this issue of one-year terms on RMR contracts. That's been a sore point and a difficult point for some time. It's been raised more than once, as Greg has said, not particularly successfully in terms of resolution.

I do see some prospect, I think one of the reasons in the ISO not being here today perhaps makes it easier for us to speak in their stead, another reason to have another workshop perhaps, Matt. One of the factors underlying that reluctance to enter into longer term contracts is that the ISO, itself, is not a -- I don't know if creditworthy is the right word, but they don't have a lot of credit behind them. They have to look to the utilities and to the other, the scheduling coordinators and the users, the participants in their markets, to pass those costs on.

And after the events of the last few years they've been reluctant to undertake any long-term commitments, which is perhaps understandable, but I think we're now at a point where, with the utilities, the big utilities, becoming creditworthy again, that it's apropos to press this issue, continue to press it, and perhaps ultimately with some more success with the ISO. They may be more willing to look at it and to make multi-year commitments than they have been. And they've got some reason that they can do that.

PRESIDING MEMBER GEESMAN: Yeah, but -- I'm going to push things to extremes here and suggest Greg, I think, would prefer that these resource adequacy requirements be met with five-year contracts.

I'm going to guess Jack would prefer to see procurement hover on ten-year contracts, and secure new plants with resource adequacy requirements met largely with one-year contracts.

So, implicit in all of that, I think, is some result that ends up expressing a preference for the new plants versus the existing plants.

But I think in both instances the utilities have balance sheet motivation to keep their contractual exposure as short as possible. You know, to the extent that the dead equivalence requirement of the rating agencies are taken seriously.

MR. BLUE: I'll say this, while we have existing plants, we do want to build new plants. And new plants require ten-year contracts at the end of the day. You can do three- to five-year contracts for existing.

However, just one more point for everybody to know. Another reason why we don't like one-year RMR contracts is just so everybody knows, we have to file a ratecase for an RMR. We're just now finishing up our 2004 RMR ratecase at FERC. We've been at there for -- we had to spend a lot of money on outside legal counsel, consultants, and we had to fly people to Washington and so it's a lot. Every year we have to do this.

It's really a very -- you know, if you get towards a cost-based system this is just added cost that doesn't necessarily have to be there. Just for the record.

PRESIDING MEMBER GEESMAN: And on your rate cases you collect the rate, but it's subject to refund, --

MR. BLUE: Correct.

PRESIDING MEMBER GEESMAN: -- based on the case resolution?

MR. BLUE: Correct.

MR. McCLARY: I would not suggest, by the way, that RMR contracts should be the substitute for the kinds of contracts that allow new plant investment and procurement to go forward. Just that I have seen, and perhaps it's a reflection of the uncertain environment we've been in, but my experience has been that one-year RMR contracts have been, as Greg points out, the transaction cost alone, and the ability to plan ahead for more than a year have been definitely difficult factors for operators of those contracts.

And, in some cases, Duke, for example, I know has been through this where your plants, from year to year, may or may not be, and you don't know, and you're taking that risk of whether you keep it in operation or not. Which may or may not, I tend to think may not, be an appropriate risk to shed to the holders of that generation, given their possible state of knowledge about where the RMR requirements will be in the next few years.

MR. PIGOTT: I wanted to answer the question from earlier today about our Pastoria and Metcalf Power Plants.

PRESIDING MEMBER GEESMAN: Yeah.

MR. PIGOTT: Pastoria has two units; the first unit is 269 megawatts. It's under construction and progressing such that it will be online later this year.

PRESIDING MEMBER GEESMAN: But not this summer?

MR. PIGOTT: It will not be for this summer, I don't believe so, but later this year. Pastoria Two is 500 megawatts and that's currently scheduled for July of '05. And on track for that.

Metcalf, 602 megawatts, and that's also on track of July of '05.

And I mean with regard to the five-year RMR, you know, I'm sure if either of those units were awarded a five-year RMR it would have some impact on those projects.

PRESIDING MEMBER GEESMAN: Right.

MR. TRASK: I'm sorry, Jack, you said Pastoria One, what was the rating? 269?

MR. PIGOTT: Yes.

MR. TRASK: Well, that does go right into our next two questions, which I'll combine. Actually, the other one is what other pending or active regulatory proceeding or legislative bill would affect the aging plant economics or retirements?

Anything at FERC or the Legislature, Congress?

MR. BLUE: Well, I know that Audra at Duke has referenced an expedited repowering proposal. I think there's a bill by Senator Bowen, 1772 or something like that -- 1776, which is out there.

There was another -- which could have an effect. I'm not saying whether --

PRESIDING MEMBER GEESMAN: That's the six-month reinstatement?

MR. BLUE: Yeah.

PRESIDING MEMBER GEESMAN: Reinstatement of the six-month siting process.

MR. BLUE: Yeah, and I'm not saying these are positive or negative, I'm just telling you this is what's out there.

PRESIDING MEMBER GEESMAN: Well, we've recommended the reinstatement of the six-month siting process.

MR. BLUE: Great. There was another bill, there was a bill by Bates, AB- I forget the number, but it ended up getting pulled and didn't make it out of one of the committees.

The other bill that's a major energy bill that appears to be at least currently, as of this timeframe, has the most momentum is AB-2006. That -- trying to think how that would affect -- I'm not sure, I haven't identified any effects to existing plants, however it would give utilities more assurance of cost recovery which would free them up to do more flexible things.

Once again, not saying whether that's good or bad, I'm just saying it's out there. And anybody else, of course, can weigh in on that. But that's the bill that I think is carried by the

Speaker Nu¤ez, and appears to be moving.

That also advocates a return to direct access, core/noncore on again. I don't really see the core/noncore market having an effect on existing plants unless we get this capacity market in place where we could have buyers and sellers transacting in different timeframes for capacity. That might be beneficial.

That's all. I don't know, Audra, do you have any other? And as far as other regulatory proceedings, I even think this proceeding and the IEPR has an effect. I'm not saying positive or negative, it has an effect. Because it's sending a signal to the Legislature, to the market, to other, you know, to companies that there's a recognition that there's an issue out there. So I think that has an effect, as well.

MR. TRASK: Well, our next two questions I'll combine, and Jack already addressed them somewhat.

Are there any planned transmission projects or power plants that have a potential to affect RMR status of an aging boiler unit between 2004 and 2008?

MR. BLUE: Do you want me to take that

one?

MR. PIGOTT: Yeah, go ahead.

(Laughter.)

MR. PIGOTT: I'm not the Otay Mesa guy, but I have to think that the transmission that's associated with the Otay Mesa project could potentially impact that.

MR. BLUE: Yeah, as the -- Calpine and us, we're kind of mud-wrestling now at the PUC. And I always tell them, it's nothing personal, just business.

But however, if the PUC approves Otay Mesa and Palomar, that will have a definite affect on the RMR status of both South Bay and Encina. It will have an affect. I don't know -- you know, and once again, that's assuming they get built in this timeframe.

There is an ultimate decision by Commissioner Wood which could prolong that. We'll just leave that at that.

MR. McCLARY: Well, in stepping far away from being in between South Bay and Otay Mesa here, obviously there are -- plans were announced for possible transmission improvements in the San Francisco area that will have tremendous impact on what is done in the San Francisco area. And what projects are built and what does, in fact, promise to be a stimulating proceeding for siting those turbines.

PRESIDING MEMBER GEESMAN: Jack, what's the current snapshot in terms of when Otay Mesa is expected to be on. You're creeping toward the end of our study period.

MR. PIGOTT: You know, I asked about that today and they said to be determined.

PRESIDING MEMBER GEESMAN: Okay.

MR. PIGOTT: So, it, I think, depends on what happens at the PUC.

PRESIDING MEMBER GEESMAN: Yeah. Fair enough.

MR. PIGOTT: Since you combined these two questions, though, in question number four, I mean certainly whenever a new project is built in a good location, and if there is an RMR contract with an existing unit, part of the reason to build that new unit there is to compete for the RMR contract.

And that has happened in the Pittsburg area with our Los Medanos facility.

MR. TRASK: Very good. Any --

PRESIDING MEMBER GEESMAN: Is Los Esteros a potential plant within this timeframe that would affect an RMR contract?

MR. PIGOTT: You mean converting the existing --

PRESIDING MEMBER GEESMAN: Yeah.

MR. PIGOTT: -- project? I can't answer that.

PRESIDING MEMBER GEESMAN: Okay.

MR. TRASK: Any other comments on transmission or new power plant effect on RMR status?

MR. BLUE: Well, let me just make one observation. The reason why all these plants in the L.A. basin do not have RMR anymore is because of the ISO, in consultation with Edison, changed their RMR criteria.

There is a study group going on right now looking at the RMR criteria with the ISO, and I would suggest that you talk to them. Which could have an impact on RMR in this time period.

PRESIDING MEMBER GEESMAN: What do you see as the timeframe for that reassessment?

MR. BLUE: We're hoping sooner rather than later, but I know now they're discussing it as part of -- requalify this, I don't know the exact answer of that. But what I do know is that they are discussing it now in regards to the 2005 RMR contracts.

PRESIDING MEMBER GEESMAN: Okay, so it's that season that they're --

MR. BLUE: Right.

PRESIDING MEMBER GEESMAN: -- looking at.

MR. BLUE: They're looking at all those issues right now.

PRESIDING MEMBER GEESMAN: Okay.

MR. BLUE: Which they'll bring to the board at the end of this, like usually they bring it October/November timeframe from the next year. So, it's going to play a part of their selection process. And I believe they just had, they're really early in that process, too. So, it would be a good opportunity to get some information at least, that might --

PRESIDING MEMBER GEESMAN: Yeah.

MR. BLUE: -- for this study.

PRESIDING MEMBER GEESMAN: That 's good advice.

MR. TRASK: Okay, moving into the

questions for panel number three, the reliability effects of plant retirements.

We've discussed this quite a bit, but I'm going to ask it. Would the retirement of any individual unit or group of aging units create a local, regional or systemwide reliability problem?

It's quite obvious that if they all retire that's going to create a systemwide problem.

MR. BLUE: Yes, yes, and yes.

MR. TRASK: Next question.

PRESIDING MEMBER GEESMAN: Well, I guess I want --

MR. BLUE: No, just kidding, but --

PRESIDING MEMBER GEESMAN: -- to come back and ask you guys, what should we make of the failure of last year's Etiwanda and Mandalay auction? Nobody bid --

MR. BLUE: Yeah. As you described earlier, I think if they were to auction that out today I'd bet you they're going to get some takers.

Now, the way that settlement was set up is every, I think it's October, the offer it up for the following year. So nobody took it last year. My guess is they're probably going to have more takers this year, potentially.

So it's all depending on I think the market dynamics. I think at that time the utilities were, they did have DWR contracts. At the end of this year, as I stated earlier, they're going to have a lot less of the DWR contracts, with our contracts expiring. So there's going to be -- they're net short for the two southern utilities are going to be a little bit larger. So there might be more incentives for them to look at that.

I don't think they had the proper incentives last year to look at it at that time when it was put out to put their toe in the water at that time. That's just my own speculation.

PRESIDING MEMBER GEESMAN: When you say the proper incentives, I'm not certain that I understand what you mean. I mean somebody said earlier --

MR. BLUE: Well, --

PRESIDING MEMBER GEESMAN: -- that there was no reliability requirement on them. But are you thinking of something else?

MR. BLUE: No. I was just making the

statement of the need for capacity, period.

PRESIDING MEMBER GEESMAN: Okay.

MR. BLUE: The need for capacity is probably going to be greater in 2005 than it was, what they predicted it was back then in 2003 for 2004. Also they will have less contracted capacity through DWR.

My point being is that it just depends on the market situation. My guess is, as well as at that time the utilities did not have authorizations to respond to reverse RFPs in which they were granted in the January 22nd order from the PUC this year. That was one little-noticed fact in the January 22nd order, was the PUC authorized utilities to respond. They can now respond to reverse RFPs.

PRESIDING MEMBER GEESMAN: They could not previously?

MR. BLUE: No. They didn't have the authorization to do that, specific authorization. Utilities look for specific authorization before they do anything.

PRESIDING MEMBER GEESMAN: This is the belt-and-suspenders approach.

MR. BLUE: So, they may be a little --

they may be more inclined to look at one now than they would have last year, in my opinion.

PRESIDING MEMBER GEESMAN: And presumably Etiwanda also failed the ISO's RMR test.

MR. BLUE: As far as -- yes, as far as the RMR criteria, which was changed after the first couple of years, to reflect -- Edison added a bunch of capacitors --

PRESIDING MEMBER GEESMAN: Right.

MR. BLUE: -- and they allowed them to claim they didn't need them for RMR purposes. And yet now one could point to well, gee, if you didn't need them why are you calling 3000 megawatts of must-off in SB-15.

PRESIDING MEMBER GEESMAN: Well, I guess the question is what have we learned as a result.

MR. BLUE: As a result of?

PRESIDING MEMBER GEESMAN: As a result of two interruptible load experiences within seven or eight months of --

MR. BLUE: I think you need --

PRESIDING MEMBER GEESMAN: -- a failed auction.

MR. BLUE: -- I think you need capacity

at SB-15. And it needed committed. Because if it's not committed they can retire whenever. I don't think there's any -- and you asked earlier what are some of the requirements for retirement.

In other words, are there notifications. You said there might be some federal ones. And I haven't looked lately, but we've actually looked at that, of course, as we all have. What are the requirements.

I don't recall a federal requirement, but I may be wrong.

PRESIDING MEMBER GEESMAN: I thought it wa sa labor type of provision --

MR. BLUE: Okay.

PRESIDING MEMBER GEESMAN: -- where you need to notify your workforce, I want to say, 120 days in advance or something --

MR. BLUE: Oh, okay.

PRESIDING MEMBER GEESMAN: -- like that. That in effect they're about to be laid off.

MR. BLUE: Yeah.

PRESIDING MEMBER GEESMAN: Because you're going to close the plant.

MR. BLUE: Right. I will -- I'm not the guy who put that together. We had our lawyers looking at that. And I haven't reviewed the document. But I know that the notifications we were looking for, were thinking about, or discussing was, you know, the ISO, the utilities, the PUC, the Legislature, you guys, I mean stuff like that. Are there any requirements for that. There are some.

PRESIDING MEMBER GEESMAN: Yeah.

MR. BLUE: Yeah.

PRESIDING MEMBER GEESMAN: If you would have your lawyers take a look at that and let us know, it would be helpful because, you know, the ISO has said --

MR. BLUE: Right.

PRESIDING MEMBER GEESMAN: -- they only give 30 days notice, that's not enough.

MR. BLUE: Yeah.

PRESIDING MEMBER GEESMAN: And something just doesn't sit right with me on that.

MR. BLUE: I don't disagree with that, by the way. So, yeah, I'll talk --

PRESIDING MEMBER GEESMAN: Thirty days is not enough.

MR. BLUE: Yeah, I don't disagree with that. Okay.

MR. TRASK: Actually their point was that they often find out that oh, that plant was retired last week.

(Laughter.)

MR. McCLARY: I was just, on Greg's point on the Etiwanda, Mandalay auction, just maybe a slightly more pessimistic take on it would be that I think this fall if you have a similar offering you might still find that the utilities would not be ready, Edison would not be ready, to enter into it without belt-and-suspenders preapproval, no subsequent prudency review kind of approval of their entering into it. Particularly if we are at a point where resource adequacy is close to being defined, but not quite there yet.

I would say the following year would be a better year to offer. But this year I would guess the rules may not quite be there for them to feel confident that they knew what they were entering into and what they should pay for it.

PRESIDING MEMBER GEESMAN: But if I'm an interruptible customer aren't I pretty upset about that?

MR. McCLARY: Yes, you are. You're upset right now.

PRESIDING MEMBER GEESMAN: I would think so.

MR. McCLARY: The interruptible customers have been interrupted and, as we know from past experience, they do not appreciate that. They do not like being interrupted.

PRESIDING MEMBER GEESMAN: And I don't --

MR. McCLARY: But I don't know that Edison's going to have the assurance that it wants to have by this October, say, in order to enter into a contract to alleviate that.

PRESIDING MEMBER GEESMAN: Well, must like the ISO, since they're not here we can talk freely, but what type of assurance are you thinking of?

It would seem to me that you'd rarely get a better offer or a better option than what Etiwanda and Mandalay represented because it was pursuant to the settlement. In the exercise of some form of prudent decisionmaking they could bid in the auction. And it would seem to me just the nature of the utility business, that that would be a noncontroversial exercise of prudent decisionmaking.

MR. McCLARY: And I would just observe that they have -- that no decision that they make has really been noncontroversial, frankly. That they would look for greater assurance than what reason would tell you was adequate assurance. That it's probably a very good deal. But there are going to be a lot of things in play through the remainder of this year, and they'll be looking at all of those.

Those might, actually, frankly could drive them in the other direction. But right now I wouldn't be confident that they would feel assured in entering into those contracts without more specific preapproval of that kind of arrangement than they've got even now.

MR. TRASK: Steve, would you say that that's somewhat of an institutional problem, more of a mind-set problem of the industry, which might be, you know, still under the old cost-of-service ratebase?

MR. BLUE: -- utility, not necessarily industry.

MR. TRASK: Right, utility, that's what I'm talking about.

MR. McCLARY: To some extent. I mean I

think it's, in part, and it's even without, you know, without denigrating that mind-set or that institutional bias, I think in some respects the utilities are facing a situation where they're emerging from a period of huge regulatory uncertainty about what is or isn't going to be approved. With the saving grace that most of it has been taken care of for them already, preapproved at very high prices and not their fault.

Now they're having to make decisions again, whether it's, you know, more the traditional kind of cost-based; whether the, you know, the extent to which they're going to have the flexibility to enter into new kinds of arrangements and whether they're going to get dinged after the fact.

They don't know yet, either. And they'll know better a year from this October than they will this October. That's about as far as I'm observing.

PRESIDING MEMBER GEESMAN: Again, back to the specific example where I believe it was an offer of a one-year contract at cost. I guess there's one door you can go through which says, well, they just didn't foresee any of this happening, so they elected not to bid on that basis.

And there's another door that I think you're suggesting be opened where even if they thought there was some potential for their interruptible customers to be interrupted twice this spring, they did not elect to bid because of concern that those costs might not be able to be recovered.

Have I got that right?

MR. McCLARY: Essentially. Or that those costs, to the extent there was a determination that interruptible -- interruption is meant to be used in the way it was used, and that buying capacity to avoid that kind of interruption you at least have to justify that, in fact, that is a more reasonable cost effective solution than interrupting customers who are on interruptible rates.

PRESIDING MEMBER GEESMAN: Now, the regulatory mechanism by which to get some form of clearance for bidding would be an advice letter?

MR. McCLARY: Yeah, I think so.

MR. BLUE: I think what they're looking

for through this implementation of AB-57, which is the whole basis of the procurement proceeding is an upfront approval, and no after-the-fact review, theoretically is what they're looking for.

PRESIDING MEMBER GEESMAN: Okay, but if I've got a notice that Etiwanda, or rather Reliant, is going to hold this at-cost auction in 60 days, I think the mechanism available to me, as a utility, is to go in with an advice letter and say, hey, I'd like to big on this, is that okay.

MR. BLUE: Possibly. There's also the door number three, which I don't want to really talk about a lot today, but it's the conspiracy door of getting back into business totally, and squeezing out the merchant industry in California. I'm not ascribing to that, I'm just -- some people have said that. But that's the door number three.

I think the other thing that's going to be really -- give us a strong indication of what's really going on in the market is when we, you know, Edison has done an RFO. The short list is out May 28th. They'll be proceeding at some point, somehow that activity is going to come to light.

If they have a strong response that will indicate that, you know, there's at least a movement on their part. I think that they're moving in the right direction. Just have to prod them a bit, a little bit more.

MR. McCLARY: And if that RFO process goes relatively well, and something comes out of it, and it's agreed that it's worked relatively well, if I were Edison I'd feel more confident about entering into the next opportunity --

PRESIDING MEMBER GEESMAN: Yeah.

MR. McCLARY: -- to enter into contracts without being second-guessed afterward.

PRESIDING MEMBER GEESMAN: Now we heard something about the munis that may have been net short this morning. I take it, at least last fall, none of them saw the Reliant auction as a good opportunity?

MR. TRASK: And there were no responses from anyone, muni or otherwise.

Well, we're down to the last two questions. And I should note that it's good that we brought up the Etiwanda, the second question here on reliability is how are aging units used to alleviate congestion on interties in southern California or other parts of the state. And it's one of the things we did learn was that the Etiwanda units are used rather semi-frequently to alleviate congestion.

Any other comments on that question?

MR. BLUE: Must-offer. What's happened a lot in the utilities, for whatever reason, had a problem forecasting their load accurately. And to date, hopefully if I'm wrong somebody will correct me, to date there hasn't been any extensive penalties imposed on the load side.

Right now there's penalties of the generation side, but not the load side. That, I think, is going to be fixed eventually, but the under-scheduling of load is what causes, a lot of times, the ISO to have to go out the day of and ramp up, and call must-offers.

The other issue, I think, that is really why they're having to do some of this is because the load is spiking faster. I mean average load may be up, but there's a lot of -- the hot spells we have had have been pretty hot so far. And, you know, the load, people are using, I guess -- I don't know if the population has grown that much, but our electric load has grown. And people are using -- they don't seem to be cognizant of the rolling blackouts we had, it just seems to us.

Usually those events occur on the third or fourth -- third day of the hot spells, usually when the day it hits.

And I would say what's happened, at least on one of the occasions, there's plenty of generation up north. When the load spikes in the south, it tries to come down just by the laws of, you know, nature. Electricity is trying -- but it gets congested. The lines get congested. Therefore, they have to call on other units down south to alleviate that congestion right there.

So, it's happening, probably more frequently. And once again I would suggest getting some more facts from the ISO on how they use this. And I think that would be illuminating to --

MR. TRASK: Clearly intend to do. I should, during the lunch break I did a little investigation. We had the hottest spring on record this spring, primarily in March and April. So I did see if there was any correlation between very hot springs and very hot summers. And essentially there aren't any.

The two previous hot springs, second and third highest, were also in the last, I think, 15 years. And both of those summers were quite average as far as number of days over 100 degrees.

Well, the last question on our list is then what tools are available to study the local and regional reliability problems that could be created by the retirement of aging units.

MR. McCLARY: Well, and you've heard this one from me before, Matt, that piggybacking on the ISO's study process is the biggest leverage you can get on this whole issue.

And it appears to me that you're working well with them and doing exactly that.

MR. TRASK: Yes, I must say I've been very pleased with the level of cooperation we're getting at the ISO. And just finding out the right people to talk to has been very illuminating.

PRESIDING MEMBER GEESMAN: I want to go into semantics again, though. I think I now understand the consensus that local reliability means local reliability area such as the ISO utilizes it. That was suggested to us earlier and I think that's a very good suggestion.

I don't know what regional reliability

is.

MR. TRASK: We were using that, and you're right, we need to define these better. We were using that primarily just as southern California, Los Angeles area, San Diego area, Bay Area. And essentially that's it. The areas where there are RMR problems, and areas where the interties are congested in between them, so it would be difficult to move generation from one region to the next.

It's more of a, I guess you'd say, a somewhat larger, overarching territory that generally would have local reliability regions within it, more localized reliability regions, as the ISO defines them.

PRESIDING MEMBER GEESMAN: Okay.

MR. BLUE: Just to go a little bit larger in a region-wise. This Wednesday the WECC is holding its first resource adequacy task group meeting in Portland. Which the ISO will be there and a lot of folks will be there.

They're looking at this -- the WECC is starting to look at this issue on a west-wide basis. Because one of our concerns is not only is load growing here, load is growing in the other states, as well. Based on evidence we've seen.

So, it's an issue for the west. And I would encourage at least monitoring by the CEC to see what's being said there. If there's anything there that could be of interest to you guys on an ongoing basis. I know that the -- a lot of the folks will be up there from California talking about a lot of these issues.

But it will be interesting to hear what some other states around California have to say about resource adequacy. That could also be illuminating on how it affects our import situation here in California. Thereby, how it affects the existing power plants.

But, once again, that's a beginning of a process that will probably go on beyond the conclusion of this study. However, it might be of benefit.

PRESIDING MEMBER GEESMAN: We pretty actively participate in the WECC process. I guess I don't completely agree with you there. I think that in many instances, because of our own failings, in terms of adequately planning and building the transmission system, we've created some instate problems for ourselves that out-of-state imports don't immediately lend much assistance to.

And I note that the Fitch report here earlier this week pointed to the WECC as having a pretty substantial reserve margin. I think they said 40 percent. That can dissipate pretty quickly in the face of a year or two of strong economic growth.

But I'm a little wary of drawing false comfort from it because we simply do not have the intertie capacity to make good use of that when we actually need it. And I think that our instate requirements, particularly during the period of this study, are likely to dominate our regional considerations. And I use the word regional in a WECC way.

MR. TRASK: All right, gentlemen, that's all the questions we had. We did, on our agenda, reserve some time here for speaking merely on the closure of the aging plant study, where we go from here.

So, any comments on that issue.

MR. BLUE: I would reiterate what I said earlier, that I don't know if you wait till your draft, or whatever, but the sooner you start having briefings with legislative staffers and even Legislators, the better.

Because I'm not sure that some of them appreciate the situation we're in, yet. And I know we're doing it as much as we can. Other folks are doing it as much as they can.

And, you know, having an official report from this agency will go a long way to at least letting people know that, you know, we still are not out of the woods yet. And I would encourage, as soon as you can, start, even if it's preliminary, even if it's, you know, early warning, whatever, just starting a dialogue with the Legislature on this would be very helpful to California as a whole.

PRESIDING MEMBER GEESMAN: We intend to do that.

MR. BLUE: And in closing, time is of the essence.

(Laughter.)

PRESIDING MEMBER GEESMAN: Matt, I would suggest that we schedule basically a repeat of today to try and rope in the other participants that weren't able to be here. And that we do that as soon as you can reliably project their ability to attend.

MR. TRASK: I was going to say, as soon as we can find a date when the PUC is not having a proceeding, nor the ISO, nor FERC.

PRESIDING MEMBER GEESMAN: I want to thank everybody very much. This has been very helpful.

We'll be adjourned.

(Whereupon, at 3:32 p.m., the workshop was adjourned.)

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CERTIFICATE OF REPORTER

I, PETER PETTY, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission Workshop; that it was thereafter transcribed into typewriting.

I further certify that I am not of counsel or attorney for any of the parties to said hearing, nor in any way interested in outcome of said workshop.

IN WITNESS WHEREOF, I have hereunto set my hand this 28th day of June, 2004.